Automated Distribution Network Planning with Active Network Management

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A thesis submitted in fulfilment for the degree of Doctor of Philosophy

The University of Edinburgh

February 2017

Abstract

Renewable energy generation is becoming a major part of energy supply, often in the form of distributed generation (DG) connected to distribution networks. While growth has been rapid, there is awareness that limitations on spare capacity within distribution (and transmission) networks is holding back development. Developments are being shelved until new network reinforcements can be built, which may make some projects non-viable. Reinforcements are costly and often underutilised, typically only loaded to their limits for a few occasions during the year. In order to accommodate new DG without the high costs or delays, active network management (ANM) is being promoted in which generation and other network assets are controlled within the limits of the existing network. There is a great deal of complexity and uncertainty associated with developing ANM and devising coherent plans to accommodate new DG is challenging for Distribution Network Operators (DNOs). As such, there is a need for robust network planning tools that can explicitly handle ANM and which can be trusted and implemented easily.

This thesis describes the need for and the development of a new distribution expansion planning framework that provides DNOs with a better understanding of the impacts created by renewable DG and the value of ANM. This revolves around a heuristic planning framework which schedules necessary upgrades in power lines and transformers associated with changes in demand as well as those driven by the connection of DG. Within this framework a form of decentralised, adaptive control of DG output has been introduced to allow estimation of the impact of managing voltage and power flow constraints on the timing and need for network upgrades. The framework is initially deployed using simple scenarios but a further advance is the explicit use of time series to provide substantially improved estimates of the levels of curtailment implied by ANM. In addition, a simplified approach to incorporating demand side management has been deployed to facilitate understanding of the scope and role this may play in facilitating DG connections.

Acknowledgements

First and foremost, I wish to like to express my deepest appreciation to my supervisor, Professor Gareth Harrison, for his kindness, support, knowledge, guidance, and encouragement in pursuing this PhD. Without you providing this opportunity my PhD and this thesis would not have been possible.

Many thanks must go out to my colleagues/friends within the Institute for Energy Systems for their support, inspiration and providing a listening ear throughout.

I also wish to gratefully thank the EPSRC and the school of engineering, herein, at the University of Edinburgh for the financial support provided throughout this PhD where I have gained valuable experiences and friendships.

To my parents, Steven and Catherine Conner; my sister, Laurie Conner; my brother, Jim Conner and my family and friends for all the support and encouragement throughout my time at University.

Finally, an enormous thank you belongs to my fiancée, Jennifer Thomson, who has endured many of late night discussions while pursuing my PhD. Thank you for caring, encouraging and supporting me throughout, especially during writing up, when we didn’t spend much time together and you had to organise a great deal of our wedding alone.

Declaration

I, Steven Conner, declare that the content of the thesis and the results presented in this thesis unless otherwise referenced are my own work for fulfilling the requirements of the PhD study. The work has not been submitted for any other degree or professional qualification.

Signed:

Date:

“Strive for perfection in everything you do.

Take the best that exists and make it better.

When it does not exist, design it”

Sir Henry Royce

(1863 – 1933)

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Chapter 5 Time Series Approach for New Expansion Planning Framework

Abbreviations

ACVS	Advanced Compensation Voltage Strategy
AND	Active Distribution Network
AMI	Advanced Metering Infrastructure
ANM	Active Network Management
ARC	Accelerating Renewable Connections
ASC	Autonomous Substation Controller
AuRA-NMS	Autonomous Regional Active Network Management System
AVC	Automatic Voltage Control
AVRS	Automatic Voltage Reference Setting
BaU	Business as Usual
CBR	Case Base Reasoning
CHP	Combined Heat and Power
CLASS	Customer Load Active System Services
CLNR	Customer-Led Network Revolution
CP	Constraint Programming
CSP	Constraint Satisfaction Problem
CVC	Coordinated Voltage Control
DECC	Department of Energy and Climate Change
DNO	Distribution Network Operator
DG	Distributed Generation
DSM	Demand Side Management
DSR	Demand Side Response
EHV	Extra High Voltage
ENA	Energy Networks Association
ESQCR	Electricity Safety, Quality and Continuity Regulations
ETPSG	European Technology Platform Smart Grids
EV	Electric Vehicles
FITs	Feed-in Tariffs
FL	Fuzzy Logic
GSP	Grid Supply Point
HP	Heat Pumps
IET	Institute of Engineering and Technology
kW	Kilowatt
kWh	Kilowatt-hour
LCN	Low Carbon Network

LCNF	Low Carbon Network Fund
LDC	Line Drop Compensation
LIFO	Last-In-First-Off
LV	Low Voltage
MAS	Multi-Agent System
MV	Medium Voltage
MW	Megawatt
MWh	Megawatt-hour
NFG	No-Firm Generation
NGET	National Grid Electricity Transmission
NIC	Network Innovation Competition
NINES	Northern
NMS	Network Management System
NNs	Neural Networks
NPV	Net Present Value
Ofgem	Office of the Gas and Electricity Markets
OHL	Overhead Line
OLTC	On-Load Tap Changing
OPF	Optimal Power Flow
PF	Power Factor
PFC	Power Factor Control
PFM	Power Flow Management
PV	Photovoltaic
PV	Present Value
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RTU	Remote Terminal Units
SCADA	Supervisory Control and Data Acquisition
SE	Successive Elimination
SGF	Smart Grid Forum
SHEPD	Scottish Hydro Electric Power Distribution
SOP	Soft-Open Points
SPEN	Scottish Power Energy Networks
SVC	Static Var Compensation
SVR	Step Voltage Regulator
TSO	Transmission System Operator
UKPN	UK Power Networks
VPP	Virtual Power Plant

List of Symbols

Sets:

B	Set of buses (indexed by b).
K	Set of contingencies (indexed by k).
L	Set of branches (indexed by l).
M	Set of periods within the year (indexed by m).
T	Set of years (indexed by t).

Parameters:

$V_{b,min}$	Minimum voltage at b.
$V_{b,max}$	Maximum voltage at b.
$d_b^{(P,Q)}$	(P,Q) demand at bus b.
$\phi_{g,min}$	Minimum power factor of generator g.
$\phi_{g,max}$	Maximum power factor of generator g.
f_l^+	Maximum MVA (S) flow on branch l.
λ_{curt}	Curtailment factor.

Variables:

C_l	Total net present value investment cost of a set of branches l.
Z_l	Vector of potential upgrades for branches l.
V_b	Voltage at b.
$(p,q)_g$	(P,Q) output at generator g.
$f_l^{(1,2),(P,Q)}$	(P,Q) injection onto l at (start, end) bus.
p_g^{curt}	Curtailed power at generator g.
$(p,q)_x^X$	(P,Q) power flow from the GSP x.
ϕ_g	Power factor of generator g.
τ_m	Duration of period m, within the year.
ω_m	Generation relative to nominal capacity as dictated by variable resource in m.

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Chapter 1

Introduction

1.1 Thesis Background

For many years the UK has been blessed with a wealth of energy resources, mainly relying on the use of gas, coal and oil to generate our electricity, heat our homes and fuel our transport. Depletion of our domestic fossil fuel supplies has increased the cost of energy and put our security of supply at risk. The UK Government set targets in 2009 to increase the use of renewable energy, with an overall energy consumption of 15% from renewable sources by 2020 [1]. Results of analytical studies suggest this is achievable by producing around 30% of the UK electricity demand from renewables [2]. With this in mind, the power industry is under a significant transition towards providing electricity from low carbon and renewable generation. Further incentives for deployment such as the Feed-in Tariff (FIT) [3] launched in 2010 and the revised Renewable Obligation (RO) [4] introduced in 2009 have accelerated the connections of renewables. Many of these connections are on the distribution network and are known as Distributed Generation (DG).

The traditional distribution network was never designed to accept large levels of generation therefore, great challenges have been encountered. Several technical impacts from connecting such generation have been experienced and there are promising solutions in some cases. Combining this with providing an enhanced security of supply and reducing the cost of energy for users brings enormous challenges.

Active Network Management (ANM) is expected to be rolled out within the UK's distribution network to improve handling of network constraints in an 'intelligent' way [5-8]. This supports the transition towards a 'smart grid' environment where the existing assets can be utilised to their maximum. Benefits include: reducing the carbon footprint of the power industry; increased security of supply; and investment deferral, which in turn will cut energy bills. Additionally, "smart grids" will "free up" extra headroom for greater connections of DG by actively monitoring network conditions in real-time and releasing capacity when available.

However, the main challenges in designing these active distribution networks are complexity and uncertainty. These include but are not limited to the type of technology; the location within the network that the DG is connected to; the timing and location of power output; and the availability of the renewable source. In addition there are a number of alternative approaches to resolving the operational challenges of networks with high penetrations of DG and this makes choices about potential solutions difficult in terms of where best they might be located, which combinations of options will work best and in what conditions. These factors present a difficult test for network designers and, as is asserted here, many of these challenges can be addressed by the development of new planning strategies which consider these various variables in an automated way to reduce the burden on the design engineer. Accordingly, this thesis is concerned with the development and implementation of a new expansion planning framework which aims to deal with the uncertainties and complexities associated with active networks.

1.2 Research Hypothesis, Objectives and Scope

The hypothesis of this research is that:

> Automated planning of distribution networks with active network management will be essential to realise the benefits of renewable distributed generation in terms of deferring or avoiding traditional network reinforcements.

The objectives and scope of this research include the following:

1. *To gain an insight into how variable generation, real time control and more complex alternatives of ANM will affect the operation of the distribution network, most noticeably with regard to power flows.* Distributed generation creates bi-directional power flows through the distribution network. This causes issues with protection, voltage and thermal limits and fault currents. Any planning strategy must built around an enhanced understanding of

distributed generation and ANM in terms of operational changes for the existing distribution network.

2. *To extend previous efforts on automated planning techniques to provide a better understanding of the effects of variability in renewable generation on network investment deferral.* Current procedures use only one "worst case" scenario that ignores variability and will tend to poorly estimate the level of investment deferral achievable by distributed generation. Integrating time series modelling alongside real time control techniques such as ANM within novel planning strategies will enhance the level of investment deferral by considering real scenarios.
3. *To develop methodologies to simplify the process of planning active networks by embedding control system actions within a wider planning framework.* An automated time series planning framework which is interchangeable amongst the various load flow software packages and control systems is desirable. This would enable a host of network operators to incorporate the novel wider planning framework using existing licensed software and the various available ANM approaches that are currently being utilised.

1.3 Research Methodology

The two main drivers for reinforcements on the distribution network are growth of demand, which has been the case for some decades and more recently the connection of generation [9]. 'Planning' of the distribution network enables the reinforcements to be prepared for system operation and adhere to the Engineering Recommendation P2 standards [10,11].

Strong indication from the IET Power Network Joint Vision Technical Report [12] implies that a number of different control facilities can provide a more cost effective means of improving the capability of the network without providing additional or more highly rated primary assets. Taking this in to consideration and with the existing planning approaches, lack of consideration for integrating DG, a new expansion planning framework has been developed. It significantly extends previous work [13-18], by integrating a modified decentralised ANM control technique within a novel planning structure. The control system allows a change in the generator active and/or reactive power when and if required to ensure a safe and secure network. "Safe" means that the voltage remains within the limits set by statute [19] and the assets remain within their thermal limits. A "secure" network describes the first circuit outage (N-1) which can be either a fault condition or an arranged circuit outage (maintenance) where the network's ability to remain fully operational is maintained [10]. However, in reality when an asset is out for maintenance this may lead to insecure operation as any subsequent fault may not allow the network to remain fully operational.

The technique was initially developed using worst-case scenarios consisting of key combinations of demand and generation, notably maximum demand - minimum generation and minimum demand - maximum generation. The latter is the current condition used to specify the need for upgrading network infrastructure.

The worst case scenarios occur for only a small percentage of the overall time with demand and generation focused somewhere in between. This suggests that the design of any future planning strategy would be well-served by incorporating better representation of the time variance of generation and demand. This may reduce the tendency for existing planning schemes to specify upgrades as the only means of permitting DG. The planning framework was developed to incorporate time series information in one of two ways.

This first employed 10 minute time series of demand and generation for typical 5-day periods in winter and summer to offer insight into within the day and seasonal patterns. This algorithm is able to capture realistic sequences of events and demonstrates a planning technique that can work with the time scales of control systems.

As this is reasonably computationally intensive a second approach was employed that vastly reduces the number of distinct sets of conditions examined. This groups combinations of demand and generation within similar and representative ranges and avoids the repeated analysis of similar profiles.

The final aspect of the work was to incorporate a simple representation of demand side management (DSM) within the framework to illustrate how DSM might influence planning schedules and the operation of decentralised ANM schemes for DG.

The validity of the new expansion planning framework has been examined through:

- Simulation using high temporal resolution demand and generation data to simulate realistic operation of the distribution network.
- Use of two test distribution networks: (1) a generic network (UK GDS); and (2) using data provided by Scottish Power Distribution for a network in East Ayrshire, Scotland with abundant wind resource, and little demand.

1.4 Thesis Contributions

For many developers of low carbon and renewable energy, connection to the distribution network is the main stumbling block due to very little spare capacity. The locations which have great wind resource are mainly in areas with insubstantial distribution networks to export the energy. However, the distribution network was never designed for the volume of generation that is currently connected and ready to be connected. The main challenges that DNOs have to overcome are voltage rise and thermal overloading issues. With existing planning processes taking only one case into consideration (maximum generation and minimum demand) these issues will trigger infrastructure upgrades. Planning strategies that make use of variable generation and demand information should in principle be more effective in demonstrating that actively managed DG connections can be granted.

An understanding of the potential for real-time operation of the distribution network shows that connecting DG does not always hinder the performance of the network and when actively managed can defer or avoid investment in infrastructure. The strategy has been proved by others to be effective in a number of selected real-world situations. What is lacking is a generally accepted method and toolkit to allow ANM to be used in practice.

The work reported in the thesis describes an extensive effort to develop such a method and toolkit. It employs the broad approach of Wang [13,15], using a heuristic algorithm coded in Python interfaced with well-known commercial software (PSS/E) to implement credible least-cost network expansion plans. This toolkit differs from Wang as it explicitly accounts for the variability of renewable generation and demand. This contributes to more investment deferral being achieved by accurately identifying the conditions and constraints of the local distribution network. In addition, this work explicitly incorporates a specific decentralised form of active management related to the work of Sansawatt [14] as an exemplar of an ANM. However, a number of key settings have been adjusted to make them less cautious to motivate greater investment deferral and DG connections and Sansawatt's approach has not been incorporated into the planning environment previously. The framework is also set up to employ a simplified version of demand side management. In saying that, the specific control systems employed are flexible and the framework has been developed with the express purpose that other approaches can be implemented in a straightforward manner. The framework is believed to be unique.

The framework has been deliberately developed to appeal to wider use in academia and particularly industry. It uses commercially available software which DNOs currently have access to promote the idea that such approaches are within reach; it is entirely feasible to swap the load flow engine for a different commercial or open source version. Importantly, the heuristic algorithm employed is relative simple and its process entirely auditable; as such it decision-making can be seen as different from 'black-box' approaches elsewhere in the literature. This may well be more appealing as the planning engineers have experience of the software and its capabilities and saves time learning new packages. It is believed that the model will provide DNOs with greater confidence that actively managed networks can accommodate extra DG and an effective means of automating their design.

1.5 Associated Published Work

There are two publications currently completed and sufficient material for two journal papers. The completed papers are provided in the Appendix.

- S. Conner, G.P. Harrison, "A Direct Comparison of Various Active Network Management Techniques," presented at CIRED Workshop, Rome, 2014.
- S. Conner, G.P. Harrison, "Demonstration of an Actively Managed Planning Approach for Connection of Renewable Generation," due to be presented at CIRED Conference, Glasgow, UK, 2017.

1.6 Thesis Structure

The thesis is structured as follows:

Chapter 2 describes background knowledge associated with traditional distribution networks and distributed generation. It also states the impacts created by the growing connections of DG. It defines low carbon and renewable generation connected at the distribution level. A concise discussion on the transition towards a smart distribution grid is included.

Chapter 3 provides an explanation of the state-of-the-art in active network management approaches, concentrating on managing voltage variations and thermal overloads. Other control methods are portrayed in conjunction with current research activities being carried out across the UK and Europe. Demand Side Management and "Smart Grid" solutions and activities are also discussed. Current expansion planning concepts are presented with particular emphasis on how smart grid techniques can be implemented. The limitations of existing approaches are outlined.

Chapter 4 presents a scenario based expansion planning method and details the control mechanisms utilised to manage the active and/or reactive power, which in turn can remove the requirement of network upgrades and thus defer infrastructure investment. Detail of the 12-bus distribution network used to validate the new expansion planning framework is presented. The results are displayed and compared with the original model which had no control capabilities.

Chapter 5 proposes an extended model that better captures renewable variability. A time series representation is defined and two methods to process the data are used and compared: (1) applying 10-minute demand and generation data for a continuous 5-day period in both the winter and summer seasons and (2) a demand-generation correlation approach employing a full year of data that is computationally more effective. The benefits of using time series data are compared to the worst-case scenario approach.

Chapter 6 presents a more extensive case study involving a real and larger network modelled from Scottish Power Energy Networks licence area in southern Scotland. The scenario and time series correlation methods are employed and compared.

Chapter 7 discusses the overall results achieved in Chapters 4 to 6 and extracts conclusions on the research. Key issues for future work are also addressed.

A series of Appendices covering: network, demand and wind data; simulation environment; and publications are provided.

Chapter 2

Distribution Network

2.1 Introduction

This chapter presents a concise literature survey on the existing distribution network, considering the type of configurations, planning methods, and the impact of Distributed Generation (DG). The chapter opens with an introduction to the distribution network and the different configurations that can be found in the UK. The traditional design behind the existing system is described in detail. A definition for DG is provided together with descriptions for a number of generation types. Under present-day planning methods, technical constraints are encountered frequently and an excessive number of DG projects are unable to obtain a connection to allow the development to progress, without triggering upstream infrastructure upgrades. The Distribution Network Operators (DNOs) have embraced some change with the growing numbers of DG connections; however, the design approaches are very limited and discussions why they are currently not effective will be explained. Finally discussions on why DNOs must evolve towards a smart distribution network is detailed.

2.2 Distribution Network without Distributed Generation

This section describes the UK electricity distribution network, initially providing a brief explanation of the complete UK electricity network. Background knowledge on configurations, regulations and planning practices are discussed.

Traditional methods of supplying electrical energy to consumers began by the means of large scale generating stations. On the whole these were situated near the fuel source, such as coal or away from populated areas aimed at safety and access to cooling water, for instance nuclear power stations. In general the demand centres would be some distance away from the generation stations. This electrical energy required transportation by means of a network of overhead lines, underground cables, transformers and safety equipment. Figure 2.1 illustrates the four main components of the UK electricity system [20]: (i) generation; (ii) transmission; (iii) distribution; and (iv) demand. In general the distribution network is the electrical system between the Grid Supply Points (GSP) fed by the transmission network and the end users, such as industrial, commercial and domestic consumers [21].

2.2.1 Distribution Network Configurations

Typically distribution networks can be classified into five main configurations: (i) mesh; (ii) interconnected network; (iii) link arrangement; (iv) open loop; and (v) radial systems, as shown in Figure 2.2 [22] (circles represent substations). Different benefits and risks are associated with each configuration and include cost and security of supply. The higher the security of supply generally indicates a greater cost.

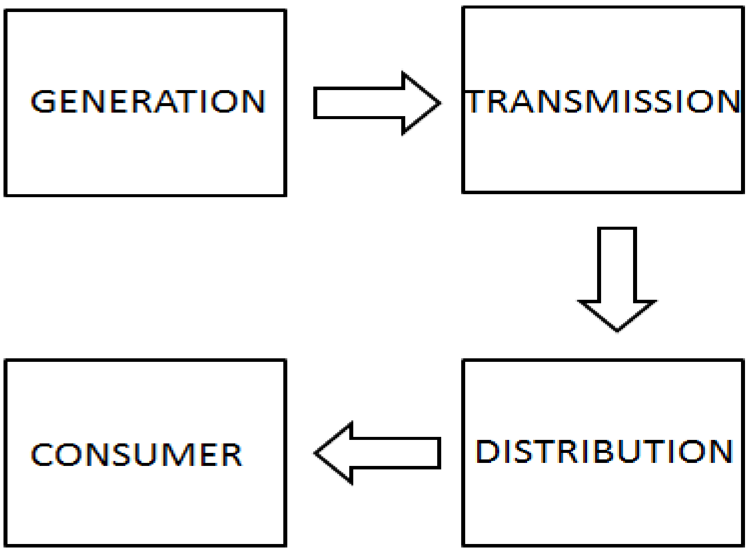

Figure 2-1 - UK Electricity Network Structure.

The meshed and interconnected systems provide a higher level of security of supply and are typically used in the transmission systems. The link arrangement is commonly operated as two separate radial circuits by opening the connection. However, having the opportunity to close the connection offers the distribution network a higher level of security when one of the infeed substations is out of service. The open loop can also provide security of supply by isolating the faulted section and closing the normally open point to provide back-up. The radial arrangement is the most common configuration within the distribution network especially in rural locations and at lower voltage levels. Radial networks are the least complex and inexpensive to build, but provide no security of supply downstream from the outage.

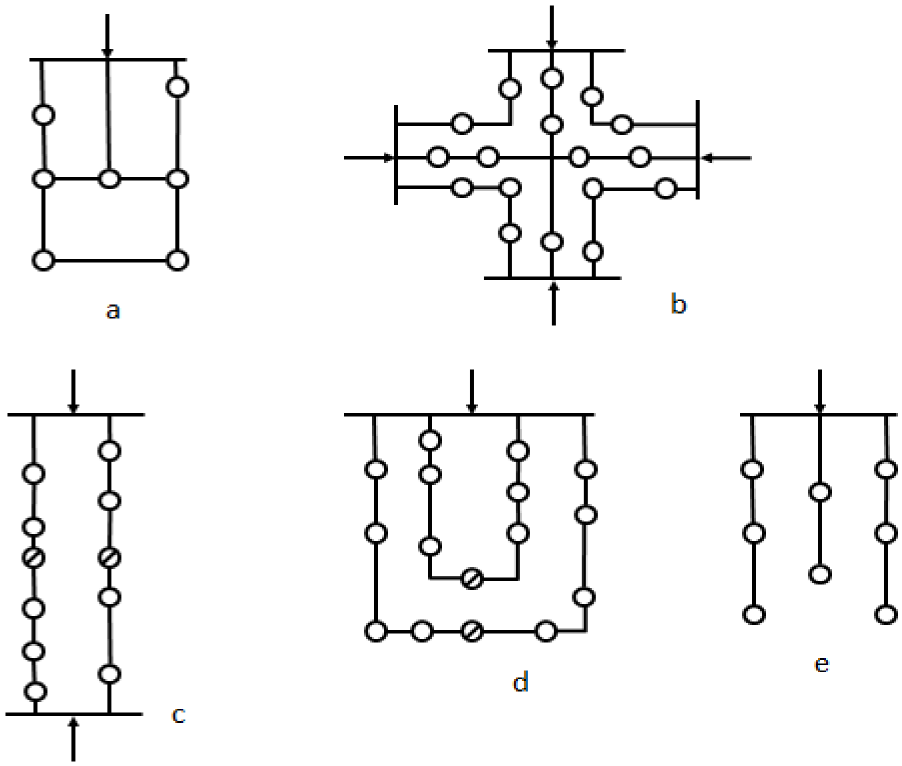

Figure 2-2 - Network configurations: (a) Meshed, (b) Interconnected, (c) Link Arrangement, (d) Open Loop and (e) Radial Networks [22].

2.2.2 Voltage Regulation

The Electricity Safety, Quality and Continuity Regulations (ESQCR) 2002 stipulate the acceptable upper and lower voltages limits set by statute within the UK electricity system [19]. There are different ranges of limits dependant on the voltage level:

- For low voltage (LV) supply (<1000V): A variation not exceeding 10% above or 6% below the declared voltage at the declared frequency.
- For medium voltage (MV) supply (>1000V and <132kV): A variation not exceeding 6% above or below the declared voltage at the declared frequency.
- For high voltage (HV) supply (>132kV): A variation not exceeding 10% above or below the declared voltage at the declared frequency.

2.2.3 Planning Procedures without DG connected

Early distribution networks were never intended to connect a high level of generation. Originally they were designed to only transfer energy from the Grid Supply Point (GSP) fed from the transmission network to the consumer. One of the main factors DNOs had to contend with was voltage drop along the line. Illustrated by Figure 2.3 [22] a single line feeder represents the MV and LV sections of a typical UK electricity distribution system. The voltage drop is dependent on distance and impedance of each sub feeder between the substation and the load connected on the lower voltage side. DNOs must regulate the voltage within the permitted limits.

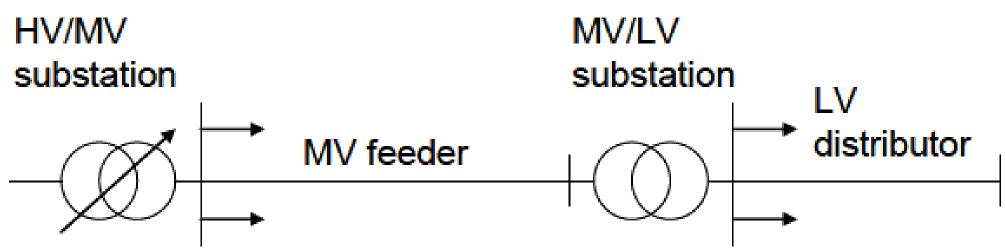

Figure 2-3- Simplified distribution network system [22].

Therefore, the voltage level at the substation must be higher than that at the point of connection, explained by Figure 2.4 and Equation (2 - 1):

$$\Delta V = V_S - V_C = \frac{RP+XQ}{V_S} \qquad (2 - 1)$$

where V_S is the primary substation voltage, V_C is the connection point voltage of the consumer, R and X are the line resistance and reactance, respectively, and P and Q are the active and reactive power transmitted from the substation down the overhead lines.

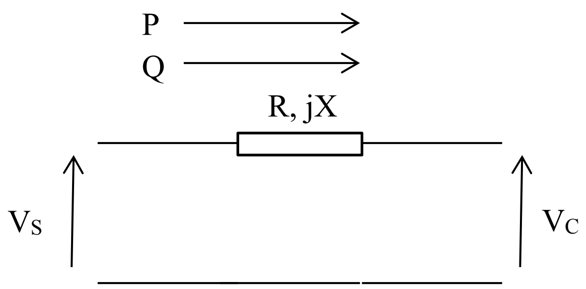

Figure 2-4 – Simple Circuit to Demonstrate Voltage Drop.

Figure 2.5 displays an example circuit, an 11kV overhead line connected to a substation. It consists of 16mm^2 copper conductors and five 100kW, 20kVAR three phase loads spread 4km apart. The total length of the circuit is 20km and as clearly shown the voltage drops as the distance from the substation increases. If the nominal voltage is set at the substation, the end of the circuit would have a voltage of 10.3kV, which is 6% below nominal and rests on the permitted limit. If the overhead line had been longer, then the voltage would have violated the limit set by statute. To this end, DNOs generally support voltage drop, by setting the voltage at the substation above the nominal voltage and are controlled by automatic voltage control (AVC), on load tap change transformers (OLTC) and line-drop compensation.

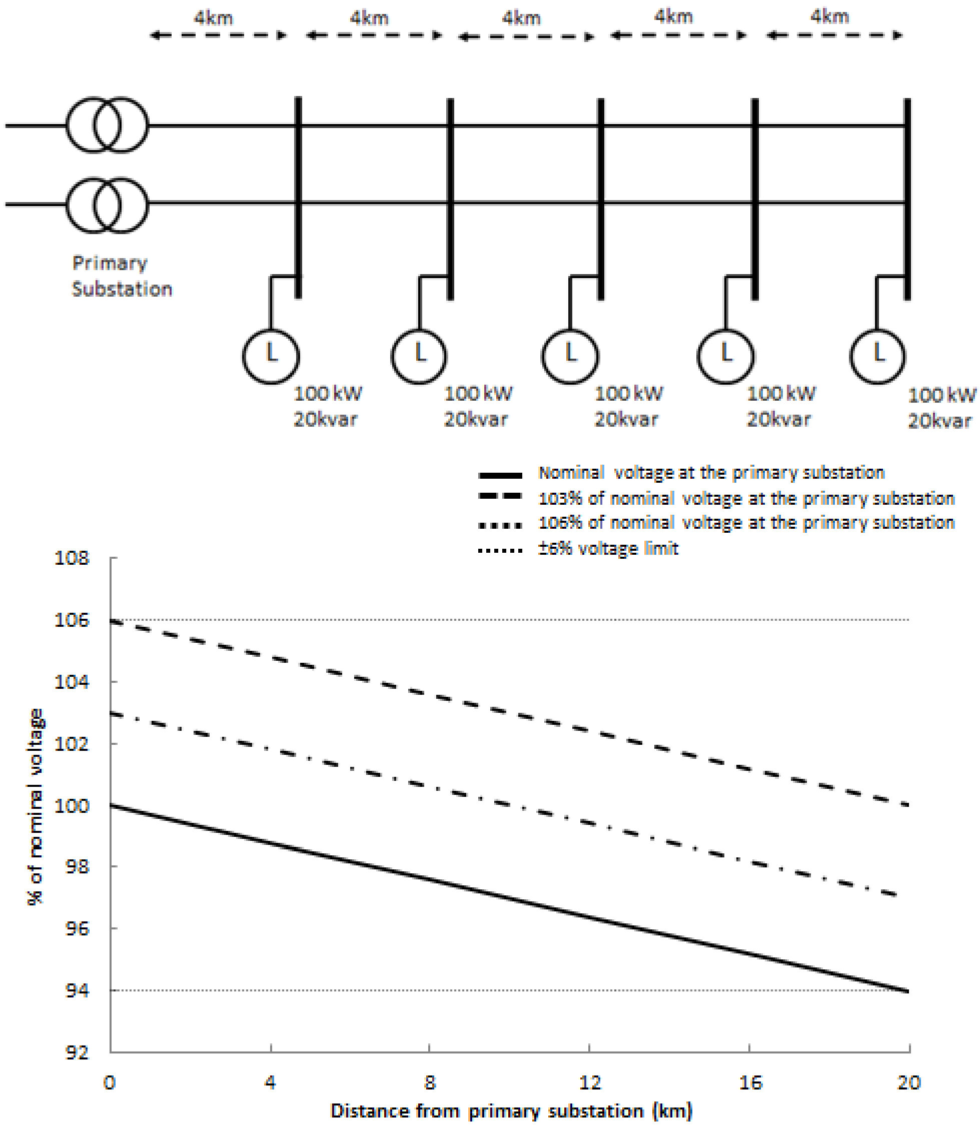

Figure 2-5 – Example Circuit to Demonstrate Voltage Drop [23].

2.3 Distributed Generation: A Definition

In this section a definition of distributed generation will be provided alongside the drivers behind their uptake. Low carbon and renewable generation technologies will be described.

There are other terms used to describe DG. These include "embedded generation", meaning generation that is embedded within the distribution network [24]. Another term is "decentralised generation", referencing the fact that the energy is generated locally to the demand rather than in large ‘centralised’ power plants. “Distributed energy resources” (DER) is an alternative phrase commonly used to describe DG.

Although increasing levels of renewable DG, as demonstrated by Figure 2.6, are being connected to the electricity networks in the UK and around the world no precise definition has been stated. Each country portrays different definitions of DG; in the UK, DG is described as a generating unit which is connected to the distribution network and generation capacity is less than plants connected to the transmission network [25]. In England and Wales the maximum voltage at distribution level is 132kV and in Scotland is 33kV. A second definition is that DG is any generation of low-carbon sources, which could include Combined Heat and Power (CHP) that are connected directly to the distribution system and where the electricity generated is consumed by the local area [26].

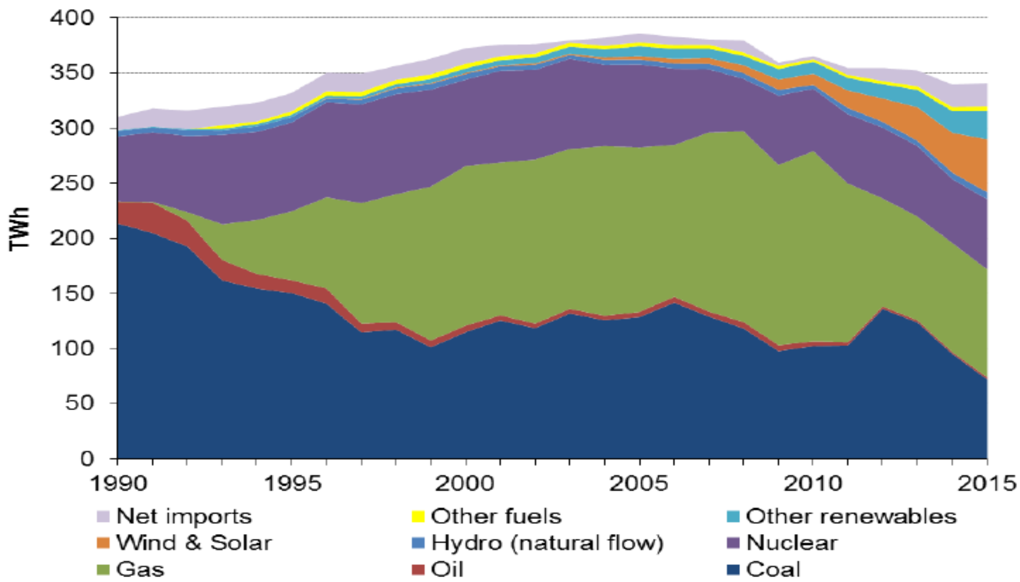

Figure 2-6 – Electricity consumption by generation type in the UK (1990-2015) [27].

Ackermann *et al* also introduced four main categories of DG each dependant on the maximum capacity as follows [28]:

- Micro DG < 5 kW;
- Small DG 5 kW < 5 MW;

- Medium DG 5 MW < 50 MW;
- Large DG 50 MW < 300 MW.

Throughout this thesis, DG with a maximum capacity between small and medium scale, supplying active and reactive power connected to the 11kV and 33kV distribution levels will only be considered. The following general definition suggested by Ackermann *et al* will also be used to describe DG [28].

> *"Distributed generation is an electric power source connected directly to the distribution network or on the customer side of the meter."*

2.3.1 Drivers

This section summarises and details the motivation for the sharp rise in DG penetration within the distribution network [25].

Environmental Concerns

Concerns over environmental impacts such as climate change are one of the key motives behind the upsurge in DG connections. With fossil fuelled generation dominant in most power systems, renewable and low carbon DG is seen as a key way of reducing carbon emissions.

An increase in renewable energy generation has been targeted by EU member states. In Europe, the target is to achieve 20% of its energy share by renewables, alongside a 20% reduction in greenhouse gas emissions and 20% more energy efficiency [29, 30]. The UK has a 15% target of providing energy generation by renewables by 2020. The UK Renewable Energy Strategy report [31], suggests that this target is likely to be provided by 30% of electricity generation, 12% of heat and 10% of transport energy generated by renewables. In 2015 25% of electricity came from renewable generation [32].

Technological Innovation

Innovation in technology has progressed due to increasing environmental concerns and changes in Government policy. With the requirement for reduction in carbon emissions different generation devices have been developed since the distribution network was originally designed, for example, wind, solar, wave, tidal and biomass. Many innovative technical solutions have been developed in recent years to allow the integration of these new generating technologies.

Government Policy

In 2008, the Government set up the Department of Energy and Climate Change (DECC) to oversee energy and climate change mitigation policy[1]. With one of DECC's key policy areas being the UK's energy supply, a policy was developed to ensure supplies were secure, low carbon, and fuelled from a diverse range of energy supplies. Energy prices also have to remain at affordable levels. A number of incentives to encourage the uptake of renewables were developed:

- Renewables Obligation;
- Feed-in Tariff;
- Contracts for Difference.

The Renewables Obligation (RO) was introduced in 2002 and has been the main support mechanism for large scale renewable projects in the UK [4]. UK electricity suppliers are obligated to source an increasing proportion of the electricity they supply from renewables. Renewables Obligation Certificates (ROCs) are issued to accredited renewable generators, the amount dependent on the generation technology and output. ROCs are administered and issued by OFGEM, providing an average of one ROC per each megawatt hour (MWh) of eligible renewable output. Offshore wind are issued two ROCs and onshore wind 0.9 ROCs. Generators sell ROCs directly or through traders and brokers to licenced suppliers. Suppliers then demonstrate to OFGEM that they have met their obligation.

The Feed-in Tariff (FIT) was introduced in 2008 and took effect from April 2010. FIT is an incentive scheme and open to generators of capacity up to 5MW. A generation

[1] In July 2016 DECC was closed and its remit taken over by the Department for Business, Energy and Industrial Strategy (DBEIS).

tariff is received for each unit (kilowatt hour or kWh) of electricity generated [3]. The rates are dependent on:

- The size of the system;
- Technology installed;
- When the system was installed.

In addition to the generation tariff, the developer can also sell excess electricity to the supplier.

Electricity Market Reform (EMR) was legislated via the Energy Act 2013 [33] and introduced a new incentive in 2014 [34]. The Contract for Difference (CfD) is due to replace the RO in 2017. CfD is a new mechanism which will provide long-term revenue stabilisation for new low carbon schemes [35]. It will benefit projects such as offshore and onshore wind farms, large scale solar projects, hydro schemes as well as nuclear and provides a stable framework for financial investors. A strike price is agreed when contracts are awarded. This strike price is basically a guaranteed price for the renewable electricity. It works by following the market price and when the market prices increase beyond the strike price, the generator pays back the difference. However, when the market price dips below the strike price, a top-up is paid to the generator. This contract is initially awarded for a 15 year term and could be open for extensions in the future depending on market conditions.

Security of Supply

Increasingly the UK is dependent on relying on importing fuels such as gas, coal and oil to meet our energy needs. With this brings a great deal of uncertainty on cost and reliability of supply. Having a diverse combination of energy sources is therefore advantageous and helps the UK be less exposed to the rise in price for fuel or restriction in availability. With fossil fuels being used much more quickly than they can be created, eventually they will become scarce and prices will rise. If the UK can provide alternative sources of energy then the security of supply will be maintained in the future.

The system operator has developed an ancillary service market to help maintain the security of supply while the transition towards a low carbon network is accomplished. The capacity market service is reviewed in section 2.4.3.

2.3.2 Types of Low Carbon and Renewable Generation

Advances in technology have enabled an increase in low-carbon and renewable DG. The total renewables share of electricity generation is increasing year after year in the UK. The 2016 Q1 share rose from 22.8% in the previous year to 25.1% [36]. The total electricity generated from renewables in 2016 Q1 increased by 6.4% from the previous year to a new record high of 23.2 TWh [36]. This section lists and describes the various technologies that are being developed and connected throughout the distribution network:

- Solar Photovoltaic (PV)
- Wind (Onshore and Offshore)
- Combined Heat and Power (CHP)
- Wave
- Tidal
- Biomass
- Energy from Waste

Solar

Photovoltaic is now a relatively well developed technology and been has employed for over 20 years. Mass production began in 2000, however, it wasn't until the FIT incentives were released that uptake of solar systems took off in the UK. There has been an increase every year since 2011 as demonstrated in Figure 2.7. In 2015 some 7.6 TWh of energy was produced by solar in the UK, an increase of 86.6% on the previous year [37]. This rate of growth will not be maintained as the government drastically reduced rates in 2016.

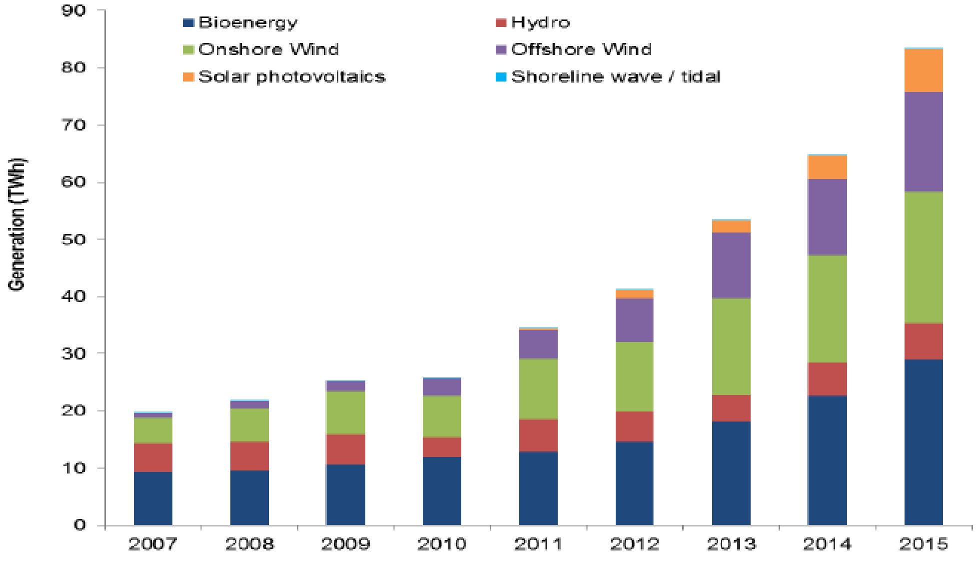

Figure 2-7 – Renewable Electricity Generation 2007-2015 [37].

Wind

Wind energy contributed the largest share of renewable electricity capacity in 2016 [38] and has been the fastest growing technology over the last decade [39]. Both onshore and offshore wind combines to make approximately 50% of the total renewable energy share. Onshore wind currently (in 2016) has an installed capacity of approximately 9.5GW, a 210% increase on 2012 figures. Offshore wind capacity reached a new high of 5.1GW in 2016 [38]. In the UK, the strength and dependability of the wind has supported the deployment of this technology. However, wind powered generators supply electricity only when the wind speed is favourable, thus they are not dispatchable to meet a rise in demand. In Q2 of 2016 there was an 18.8% reduction in energy generated from onshore wind, compared to the previous year, due to less favourable weather conditions, even though the capacity had increased. Therefore, wind energy cannot be used on its own and can only be part of a diverse energy mix.

Combined Heat and Power

Combined Heat and Power (CHP) schemes capture and utilise the heat that is a by-product of the electricity generated, which is a highly efficient process. Up to a 30% saving in carbon emissions can be sought by generating heat and electricity simultaneously, as opposed to separate conventional generation via a power station and boiler [40]. CHPs are designed to match a heat demand which would otherwise be met by a standalone boiler. This makes CHP schemes highly efficient by utilising heat which would otherwise be lost when generating mechanical or electrical power. Organisations can typically save around 20% on energy costs and reduce carbon emissions by sourcing their energy through a CHP system [40,41].

Wave and Tidal

Around 10% of Europe's wave resource can be found around the shores of Scotland. Wave energy lags a good way behind the advances seen by wind and solar technology. Only small pre-commercial systems have been developed due to the difficulty of building machines capable of withstanding the conditions. Unfortunately a number of developers in Scotland went out of business in recent years.

Tidal power is somewhat more predictable and therefore, a more reliable source of renewable energy than most alternatives. Tidal power can be classified into two generating methods, tidal stream and tidal barrage [42]. Tidal stream generators operate by extracting energy from moving water, similarly to wind turbines. The tidal stream generator is the least expensive to build and has the greatest potential to be developed. The tidal barrage uses a dam-like structure to capture energy from water moving in and out of a river: these are large structures and do not qualify as DG.

In 2016 several "commercial" projects were underway: the MeyGen tidal stream project located in the Inner Sound in the Pentland Firth will be the world's first large-scale tidal array, consisting of four turbines totalling 6MW. Nova Innovation developed the first tidal array consisting of two small scale turbines at Bluemill Sound in Shetland, rated at 100kW each. Further developments are due to extend the array to five devices. Finally, Scotrenewables are attracting investment to build and test the world's largest floating tidal turbine at a size of 2MW.

Biomass

Biomass energy is classified as a renewable energy source and one which the UK Government aims to use to deliver a low carbon economy [43]. The definition for biomass is “any biological material, derived from plant or animal matter, which can be used for producing heat and/or power, fuels including transport fuels, or as a substitute for fossil fuel-based materials and products” [44]. It can be considered a carbon neutral resource because the carbon dioxide emitted during production of energy is reabsorbed during the growth of the crop. However, there is a slight overall contribution to CO_2 emissions released during establishment, harvesting, production, supply and transportation phases [45]. Bioenergy, which includes Biomass had a 36% energy share of renewable generation in Q1 2016 [46].

Energy from Waste

Historically, the UK was very dependent on landfill for dealing with waste. Landfill diversion targets were introduced in the mid-1990s and were the main driver for a new generation of energy from waste plants [47]. Waste to energy generation provides a valuable low carbon energy and plants are designed to meet strict emission standards. Ideally all waste should be prevented, however, in reality this does not happen. Firstly, waste should be reused wherever possible, and if not, recycled. The waste which is not suitable for recycling, goes to an energy recovery centre or as a last resort, landfill. Carbon emission savings are met by generating electricity from the waste to energy plant, which would otherwise have to be met by a conventional power station. Therefore, carbon dioxide savings are made from what would have been released from the conventional power station. The overall impact is reduced by offsetting the savings from not having to use the gas-fired power station against the carbon emissions released from the waste to energy plant. The more efficient the waste to energy plant converts waste to useable energy, the greater offset of carbon emissions and thus the lower the net emissions [47].

2.4 Benefits of Integrating DG onto Distribution Network

In this section, the positive impacts created by including DG on the distribution network will be presented. While there is much focus in the electricity industry on the negative impacts from the influx of DG, there are a number of positives which are created by connections of DG. These "system support benefits" include [27]:

- Reduction in transmission and distribution losses;
- Deferment of infrastructure reinforcement;
- Providing ancillary services to the transmission network operator;
- Avoidance of TNUoS and BSUoS charges.

2.4.1 Reduction in transmission and distribution losses

Research into benefits of DG reducing the transmission and distribution losses has been ongoing for over a decade. A number of papers [23,48,49] have suggested that DG will indeed decrease loads on lines and reduce losses. However, [50] also suggests that larger DG connected to the distribution network can actually give rise to excessive losses. Losses occur when current flows through a conductor, therefore, if loads are met by local DG then the current flowing through the conductor will decrease, thus reducing losses.

2.4.2 Deferral of infrastructure reinforcement

DGs role on investment deferral is dependent on location, the quantity of active power exported from the generator and technology. When the correct level of DG is placed in the appropriate location providing secure, dispatchable electricity it can defer the requirement to reinforce the network that would otherwise be necessary due to growth in demand.

2.4.3 Providing ancillary services to the transmission system operator

National Grid Electricity Transmission (NGET) are the transmission system operator for Great Britain; they also own the transmission network in England and Wales. The system operator provides specialist services and markets collectively known as ancillary services to ensure a continuous flow of electricity and that the supply meets the demand. The main objective of the ancillary services is to provide the electricity system with support to maintain in a stable state at all times. Some of the ancillary services which can currently be provided by DG:

- Short Term Operating Reserve (STOR);
- Enhanced Frequency response;
- Intertrips;
- Capacity Markets.

Short Term Operating Reserve is a requirement from NGET to be able to supply actual demand when it is greater than forecast demand or when plant becomes unavailable. Reserve power is contracted by NGET through tenders to be available for times forecasting is incorrect and can be met by a reduction in demand or increase in generation. The minimum contracted MW capability is 3MW which must be achievable no later than 240 minutes after National Grid's instruction and must be available for a minimum of 120 minutes [51].

The system operator has to maintain system frequency at 50Hz. Due to the changing energy landscape and increasing amount of renewable generation on the system, frequency volatility has developed and NGET has had to develop new and innovative ways to manage the frequency to ensure that the energy keeps following. NGET has defined enhanced frequency response as a service that reaches 100% active power within one second of NGET disclosing a frequency deviation. This enhanced service is different from the other frequency response services on offer: primary response require a response in 10 seconds and secondary response within 30 seconds. For this new service National Grid procured 200MW of enhanced frequency response during the summer of 2016. A minimum and maximum cap of 10MW and 50MW per provider was put in place to enable flexibility on the system [52].

Commercial intertrip services are contracts between a DG developer and NGET to secure identified future constraint management requirements. Selection is composed with the aim of ensuring that the total cost of managing constraints are lower than the cost without the procurement of intertrip services [53]. Although connected to the distribution network NGET have the authority to reduce or disconnect DG to manage transmission constraints. This allows National Grid to relieve the transmission network overloads, manage system voltages, maintains system stability and safeguards a quicker restoration of the transmission network once the fault has been resolved. National Grid secure identified

The capacity market has been designed to enhance the security electricity supply by putting in place sufficient capacity to meet demand [35]. Capacity providers, whether new or existing power generators, electricity storage or capacity provided by demand side response (DSR) all have the opportunity of a fixed, predictable revenue stream on which future investments can be based on. The supplier levy will compensate the capacity market via consumer's bills. However, costs will be minimised by the nature of the auction process which will safeguard the lowest cost provision of capacity. When required, providers must deliver energy in return for capacity payments or run the risk of receiving penalties. This limits the opportunity to DG that can be dispatched.

2.4.4 Avoidance of TNUoS and BSUoS

Transmission Network Use of System (TNUoS) charges are calculated by taking the user's average demand during the three half-hour periods when the greatest national demand occurs between November and February [54]. Known as Triad, this is calculated by the zonal tariff for the user's geographical area. It is accepted that the three triad periods fall in the early evening, when demand is at its maximum. With the above in mind if a large energy user provides a percentage of its own energy from DG then a reduction in TNUoS charges will be saved.

Balancing Services Use of System (BSUoS) charges are similar to TNUoS charges and that the sum charged is dependent on the level of electricity consumed [55]. A reduction in electricity usage and/or use of DG to contribute to electricity use can lower BSUoS charges.

2.5 Impacts of Integrating DG onto Distribution Network

In this section, the negative impacts created by including DG on the distribution network will be presented.

As mentioned previously, traditional distribution networks were simply designed to receive electricity from the transmission network via grid supply points (GSP) and distribute the electricity efficiently to demand users connected within the distribution network. It was anticipated that energy would flow in one direction only. Nowadays, the ageing infrastructure and control practices have to enable connections from DG and accommodate export of electricity onto the distribution network and thus having bi-directional energy flow. Consequently, converting from a passive to a more active network results in some undesirable technical impacts [25]:

- Exceeding thermal ratings;
- System voltage rise;
- Reverse power flow;
- Contribution to fault level;
- Power quality impacts.

2.5.1 Exceeding thermal ratings

Conductors carrying large quantities of current are heated by their resistance. Sooner or later they reach a knee-point in temperature and the tensile strength of the conductor is downgraded [56]. Over a prolonged time, an increase in current, would damage the conductor, therefore there are thermal limits that maintain safe operation. Adding DG to the distribution network, can increase flows beyond this safe limit and trigger reinforcement to be able to manage additional generation. To determine if a conductor can deal with DG, load flow analysis is required to be undertaken to establish whether circuits can cope with thermal transfers of energy or upgraded assets are required.

2.5.2 System voltage rise

Another significant impact created by the connection of DG for network operators is voltage variation, especially in close proximity to the point of connection. The voltage is required to be maintained within ± 6% on nominal voltage as stated in [10]. Connecting DG to the distribution network affects the power flow and voltage profiles. For the generator to be able to export power, it is likely to operate at higher voltage than the primary substation. If the generator is able to absorb a significant quantity of reactive power, however, operation at this higher voltage may not be necessary. A detailed explanation can be found in [23].

2.5.3 Reverse power flow

Adding DG to the distribution network, means the direction of the power flow will vary depending on the power balance (difference between power produced and power consumed) [57]. Connecting large quantities of DG changes the system configuration and power injections that are not used locally have to be transferred across existing assets to the transmission network. Beyond the system capabilities, reinforcements will be required to accommodate the extra DG.

2.5.4 Contribution to fault level

A single small DG unit does not contribute a high level of fault current, however, the contribution from an aggregate of several small units or a few large units can alter the fault level to a point at which protection coordination is no longer achieved [58]. Synchronous generator fault current contribution depends on the pre-fault voltage, the sub-transient and transient reactance and the exciter characteristics of the machine. Induction generators can also add to fault current while they remain excited by any remaining voltage on the feeder. Finally, inverter fault contribution varies on the maximum current and duration of the current limiter.

2.5.5 Power quality limits

DG contribute to power quality issues including: flicker; harmonics; and phase voltage unbalance. Each issue will be briefly discussed.

Flicker is produced by rapid variations in voltage. One of the main contributors to flicker are older designs of wind turbines due to tower shadow and turbulent winds which initiate rapid variations in active and reactive power output [59]. Flicker is dependent on network characteristics, the fault level and X/R ratio at the point of common coupling is significant. Therefore a generator could be adequate at one point within the network but undesirable at others.

Distortion of network voltages, usually described as harmonics are commonly originated from power electronics devices. Soft-starters for older wind turbines are typically thyristor based and quite often cause considerable harmonics for a few seconds during start-up [59]. Newer soft-starters include shunt active filters and sine pulse width modulation techniques. All DG connections must comply with ENA's Engineering Recommendation G5/4 – Planning levels for harmonic voltage distortion and the connection of non-linear equipment to the transmission systems and distribution networks in the United Kingdom. Overall no major problems should occur from systems that use power electronics all the time. However, some early PV systems and wind turbines did produce major levels of harmonics due to using convertors based on thyristors.

Phase voltage imbalance can commonly be found in rural networks due to differences in single phase load unevenly distributed across phases. A negative effect of attempting to reduce phase voltage unbalance within a directly connected three phase generator is that the generator itself will heat up due to abnormal currents within the windings. Designed within the generators is imbalance protection, which may operate frequently in rural networks to avoid overheating [59]. This can create substantial loss of generation and has to be managed on an individual project basis.

2.6 Distribution Networks with Distributed Generation

This section describes the transition the UK power industry has had to overcome to enable the rise in connections of DG to the distribution network. Firstly, the current planning strategies performed by the network operators to incorporate DG are discussed. The reasons why these strategies are triggering infrastructure reinforcements and preventing further growth of low carbon and renewable generation is presented. Transition towards a smart distribution network is discussed.

2.6.1 Current planning strategies

Currently in the UK network operators are obligated under their distribution licence to *"plan and develop the [licensee's] distribution system in accordance with a standard not less than that set out in Engineering Recommendation P2/6 of the Energy Networks Association"* [10]. P2/6 is a guidance document on system planning, network capacity and the minimum requirements for security of supply. Compliance with the Distribution Code is an additional obligation under licence condition 9 which is designed so as "to permit the development, maintenance and operation of an efficient, coordinated and economical system for the distribution of electricity" [11]. The aim of the security of supply obligations are to guarantee that DNOs maximise asset utilisation and minimise load-rated expenditure whilst ensuring customer interruptions are minimal. At the same time, to meet the Licence and Distribution Code obligations it is essential that network security risk is also managed. This is paramount in any new planning strategies to facilitate an active network for the future. The contribution from different types of generation is defined by the "F Factor" which is a proportion of the declared net capability of the generator that is used to contribute to the P2/6 security of the network. Non-intermittent generation is considered differently to intermittent sources. The F Factor is determined from a series of tables contained within P2/6. Limitations include the uncertainty of establishing the contribution for intermitting generation. Only a small of proportion of the theoretical output is utilised, however, this could result in unnecessary reinforcements.

Network planning has become more difficult with the rise in the number of DG being connected to the distribution network. Instead of a network designed passively in the past, DNOs now have to contend with active and unpredictable power flows in all directions. Currently, under business-as-usual practices it is increasingly difficult to meet carbon reduction targets and maintain a relatively low capital expenditure, and ensure safe and secure operation on the network. To maintain safe margins under current design practises, reinforcements are required to accommodate extra DG.

The RIIO network regulation model introduced in 2015 by OFGEM [60] ("Revenue = Incentives + Innovation + Outputs"), purposely regulates the revenues accrued by DNOs to reward the development of innovation and smarter solutions. With a step in the right direction from the regulator, it is essential that the DNOs revise and modernise their planning strategies to transition towards a smarter grid. Currently DNOs use worst case scenario approaches within their planning schemes, and minimum demand and maximum generation data is utilised to determine if a DG connection can be granted. With this method, only a very small proportion of occurrences are actually captured and no reference is made to other times when demand is greater than minimum or generation is lower than maximum. This means that reinforcements are currently being triggered, when in practice this minimum demand/maximum generation may never actually exist or only exist for a small percentage of time. If the latter is true, some form of active control to mitigate the requirements for reinforcements must be attempted before infrastructure is unnecessary upgraded or replaced.

2.6.2 Transition towards a smart distribution network

Significant increases in DG has led to industry rethinking the distribution network and how to manage the new power flows to improve reliability, security of supply and the energy mix. A transformation from passive operation to an active set-up is required. One method being suggested is a "smart grid" or a "smart distribution network". The smart distribution grid concept is based on advanced automation technology techniques [61]. Advancement of measurement and sensor technology, control algorithms and information and communication equipment has allowed the development of smart grids which can actively control the distribution network in a real-time and flexible manner. A transition towards a smart distribution network will provide a long term solution and accommodate more decentralised generation to be connected and utilised by local demand users. The components required for a smart grid will include: flexible low carbon and renewable generation resources; reliable communications network; and advanced control algorithms.

Currently, there are a substantial number of projects working on "smart grid" technology which are at a range of stages, from research and development through to implementation. The research can be divided into categories such as: security of communication; system operation; controls; and regulations to name a few. A detailed literature review and discussions of the transition towards a "smart grid," will follow in Chapter 3.

2.7 Chapter Summary

In this chapter, a review of relevant literature on the distribution network and distributed generation has been presented. The configurations and regulations of traditional networks and how the increase in DG has seen the distribution network move towards an "actively controlled" network, has been discussed. A definition for distributed generation has been offered with a brief explanation for the common technology included. A summary of the benefits and impacts from integrating DG into the distribution network have been given. It is shown by the level of research involved that to promote low carbon and renewable generation at the distribution level a transition towards an actively controlled "smart" distribution network is required.

Chapter 3

Active Control of the Distribution Network

3.1 Introduction

This chapter presents a review of control strategies currently being employed on the distribution network, with a particular focus on the UK and European activities. The distribution network operators are facing technical challenges to overcome the impacts being created by the increasing number of connections of low carbon and renewable generation. Actively managing the once passive network will allow DNOs to avoid and/or defer costly network reinforcement costs. Network security is likely to be provided by actively controlling the distribution system by methods such as Active Network Management (ANM). Along with investment deferral, active management will ensure spare capacity, where available, will be opened up for DG developers to connect. Increasing numbers of control schemes have been rolled out over the last couple of years, with some beginning trials. Within this chapter the array of control schemes currently available and under trial are presented. Furthermore the extent of efforts to incorporate active networks in planning approaches are outlined.

3.2 Active Network Management

Active Network Management (ANM) and other control schemes aim to reduce the requirement for traditional capital-intensive reinforcement works and permit increased capacity of DG to be connected to the distribution network. Additionally, ANM strategies can also include use of energy storage devices and Demand Side Response (DSR) schemes.

The concept of ANM has been interpreted in various ways, but essentially the principle that electricity generated and consumed by network consumers is variable, allows DNOs to make use of this variability to optimise the existing networks assets. A reduction in costs and acceleration in connections can be achieved. ANM describes the control systems that manage generation and load to keep system parameters such as voltage, power and frequency within predefined limits. A control system uses real-time and near-real-time measurements to establish control signals which are required to be sent to demand users and generators. These will be instructions to adjust active and/or reactive power. The results of these instructions are monitored and then fed back into the network control system. A level of communication is required to allow the scheme to have access to real-time or near-real-time data but the extent is dependent on the scheme employed.

To date, there is no agreed definition for ANM; however, the Energy Networks Association (ENA) defines ANM as [62]:

> "Using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits, thereby reducing the need for reinforcement, speeding up connections and reducing costs."

As mentioned in Chapter 2, low carbon and renewable generation can provide assistance to the network operator in terms of technical, environmental and economic benefits [63-65]. For example, investment deferral of network upgrades can be anticipated, along with reduction in network losses, maintaining a secure supply and lowering electricity market prices.

Some of the earliest ANM schemes in the UK have been implemented within innovation projects, with DNOs aiming to integrate such approaches into their Business as Usual (BaU) practices [62]. Utilising innovation funds has allowed DNOs to develop ANM schemes, undertaking trials and transform them into widespread adoption. However, these incentives are limited to the first trial of the technology used by the DNO and, therefore, other methods to recover costs for full roll-out will be required.

Active management of distribution networks can involve some of the following components [66]:

- Voltage control;
- Real and/or reactive power flow;
- Equipment dynamic ratings;
- Fault level management;
- Loss minimisation;
- Frequency control;
- Network stability;
- Island operation;
- Demand side management;
- Ancillary services provision;
- Network automation.

3.3 Types of ANM

Reduction of traditional network reinforcements and the increase of capacity available to low carbon and renewable generation has been a major driver in the development of ANM. Currently, there is a wide range of deployment in ANM ranging from research based studies to implementation embedded within the distribution network. Various methods of ANM have been developed, ranging from decentralised to centralised approaches [67, 68] and covering voltage or thermal constraint management and/or multi-constraint methodologies.

Three main approaches of ANM can be categorised as follows:

- Decentralised control;
- Centralised control;
- Co-ordinated control (referred to as a hybrid approach).

3.3.1 Decentralised control

Decentralised control tackles localised issues by only analysing information from sensors on or surrounding the DG and point of connection. This reduces the level of communication burden and substantially reduces cost and set-up time. The control algorithms have no direct insight into the wider network and only perform necessary control procedures with the limited information available. Some examples include an adaptive voltage control for PV systems presented in [69]. In [70] a different method of voltage control of decentralised PV in LV network is outlined. A reactive power management approach focusing on sensitivity analysis based voltage regulation in micro-grids is addressed in [71]. Paper [72] presents work considering a decentralised reactive/active power management control strategy based on a Neural Networks (NNs) approach, with the aim to export the maximum available active power from DG with minimal curtailment. Decentralised control systems potentially enable shorter connection times for DG with less reliance on communication systems in comparison with centralised methods. Kiprakis [73] presented two methods to compensate line drop/rise. Firstly, a deterministic approach utilised a set of rules to switch intelligently between voltage and power factor control modes. The second uses a fuzzy logic (FL) controller to adjust the reference setting of an automatic power factor controller to mitigate voltage variation. Both proposed approaches verified that an increase in export of real power may be possible.

Similarly with control performed at the DG unit itself, Sansawatt [16] presents a method which is able to handle both voltage and thermal constraints without the extra burden of remote telemetry or communication between DG and a central controller.

The adaptive control scheme is a smart decentralised arrangement applied to control voltage and thermal constraint management. It works by actively controlling the active and reactive power output from the connected DG in real-time, with control actions identified from the data received in the previous time-step. Threshold and target values are utilised to maintain the voltage and power flow within the pre-defined limits. If network values exceed the threshold levels, measures are taken to reduce these to more conservative target values below the threshold. Real-time sensitivity analysis is utilised to alter the new active or reactive set points. After corrective action has been taken further monitoring enables the control scheme to determine when operation of the DG unit can return to normal. The control approach for managing voltage constraints is shown in Figure 3.1. The voltage at the DG point of connection is measured and compared against the threshold voltage, and if within the limit, the DG operates normally at unity power factor. If the measured voltage becomes greater than the threshold value, this value is lowered to the target level by becoming more inductive. Sensitivity analysis calculates the new reactive power set point to reduce the voltage at the point of connection. If the reactive power is set above the capability of the DG unit, active power curtailment will be required to reduce the voltage further to meet the target level. Again sensitivity analysis is utilised to calculate the active power set point. Once the voltage reduces, it may be possible to return the active and reactive power set points back to the initial setting to fully utilise the available generation.

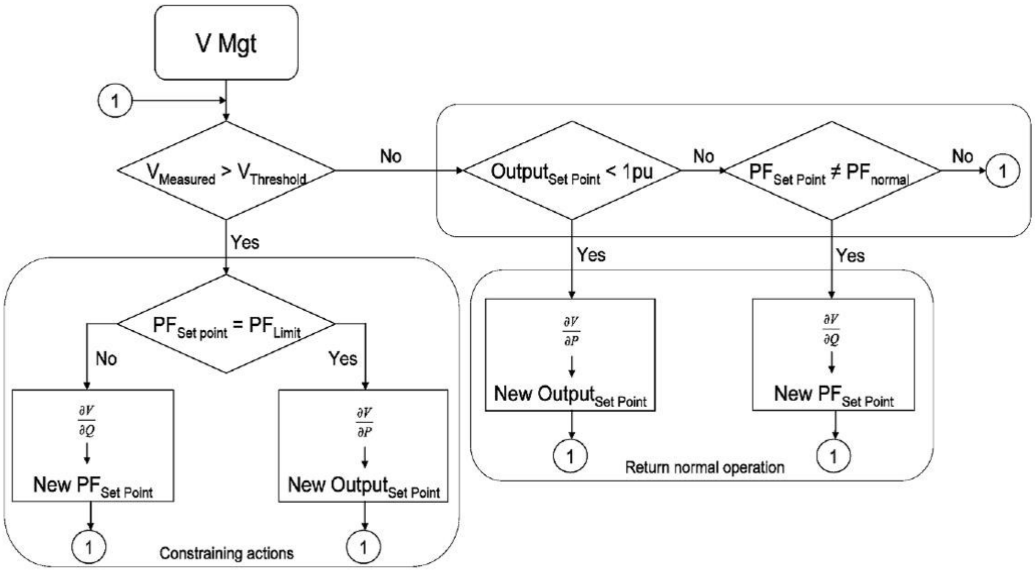

Figure 3-1– Voltage Constraint Management [16].

Thermal constraint management also utilises generation curtailment and is also based on the sensitivity analysis, as illustrated in Figure 3.2. Monitoring the apparent power flowing through the line that the DG unit is connected to and comparing this value against a line flow threshold establishes when a constraint occurs. The active power is then trimmed to a new set point, calculated by the sensitivity of the line flow to the DG unit's active power injection. This new active power is set to a line flow target, which is conservatively set below the threshold value. Similar to the voltage management, once the line loading falls below the threshold, a new active power set point is calculated by the sensitivity analysis and allows the DG unit to return towards an unconstrained state, again fully utilising the available generation.

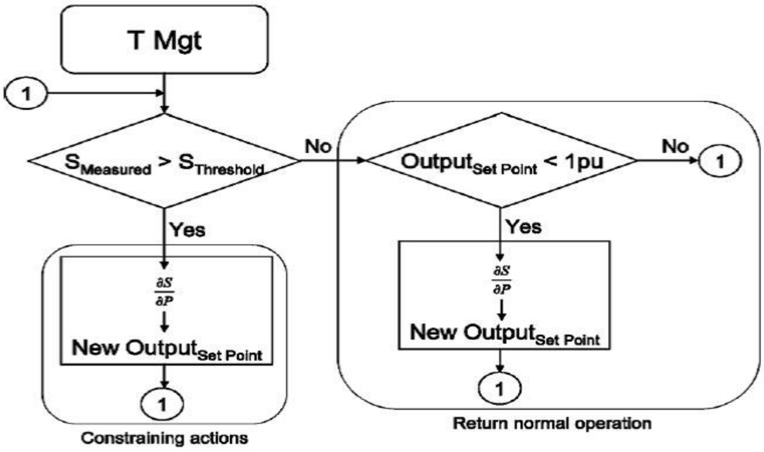

Figure 3-2 – Thermal Constraint Management [16].

Responses to constraints occur when threshold values are violated and hence are set below maximum voltage limits or the maximum line capacity. Corrective action is only taken if the threshold is exceeded. Estimated active and reactive set points are calculated to enable the network to maintain safe and secure operation. This is completed by utilising target values which are set below the threshold. Normal operation is permitted through continuous monitoring to establish if the measured values have returned below the threshold. Once normal operation resumes, the control process repeats. This method of control is particularly useful with variable generation such as wind and solar due to the frequent fluctuations in a short period of time. If only a single set point value was used there would be a risk of activating the control mechanism with trivial voltage rise or line overload that is a common feature with renewable generation.

Sansawatt *et al* developed a strategy to deal with multiple constraints, in particular voltage and thermal constraints occurring simultaneously. In isolation both voltage and thermal management could result in a "local hunting effect" in which both management schemes attempt to control the constraints at the same time. A coordinated approach which prioritises the particular schemes alleviates the above scenario and saves the control schemes being repeated unnecessarily. If multiple constraints occur, priority is granted to the thermal management ahead of the voltage scheme. This is because an increase in complex power flow due to importing reactive power to manage a voltage constraint could create a line overload. Once the line overload is under control, attention is focused on voltage management and additional curtailment may be required to ensure safe operation. Table 3.1 presents the control priorities for the multiple constraint approach.

Table 3-1 – Control priorities for multiple constraint management [74].

Voltage rise	Line thermal overload	Command
No	No	No action
Yes	No	V Mgt
No	Yes	T Mgt
Yes	Yes	T Mgt then V Mgt (if necessery)

3.3.2 Centralised control

Within a centralised control approach, control decisions are obtained by a central controller. Information regarding the status of different network elements is supplied to the central controller via various communication channels. For the centralised control approach to be effective, a Supervisory Control and Data Acquisition (SCADA) system (or similar) is important to provide the central controller with accurate knowledge regarding the voltage at each network node. At the present time, there are very few SCADA (or similar) systems available on the distribution network and most 11 kV distribution networks only provide real-time measurements at primary substations. Due to the shortage of required real-time measurements, current 11 kV networks utilise estimated measurements. Estimated pseudo-measurements provided from state estimation algorithms supply the voltage at each node on the distribution network from the limited real-time measurements and information. For estimation, the algorithms require the following information [75]:

- Distribution network topology;

- Impedance data;
- Load information;
- Limited real-time measurements.

Research started in distribution network state estimation in the 1990s with several techniques developed including: a basic weighted least squares method [76]; in [77], a process to incorporate the unbalanced nature of the distribution network with a branch current based estimator. An evaluation of the methodologies in the 2000s concluded that distribution network state estimation required more custom made methods to address the practical problems not seen in the transmission network [78]. In the early 2010s with discussions on the "smart grid" concept, Taylor *et al.* [79] suggested the development of novel state estimation techniques which integrate the DG and smart meters with low-computation time, such as the method explained in [80] based on using the Hamiltonian cycle theory. The Hamiltonian cycle theory is a nondeterministic polynomial time complete (NPC) problem, which determines a single simple cycle that covers each vertex (node) exactly once. In this way, distribution system state estimation can be formulated as an integer linear programming problem.

Some optimal power flow (OPF) approaches have been developed. The Network Management System (NMS) developed by Alnaser and Ochoa [81] adapts and extends an AC OPF based optimization engine. It determines the best set points for the available controllable resources. The architecture for their proposed NMS is presented in Figure 3.3. Another OPF approach developed by Robertson *et al* [82] employs 'real-time' online scheduling of network control settings to better integrate variable DG. It combines three control techniques to enable the DNO to control network assets and dispatch DG active and reactive power. This enables regulation of network power flows and voltage within acceptable levels.

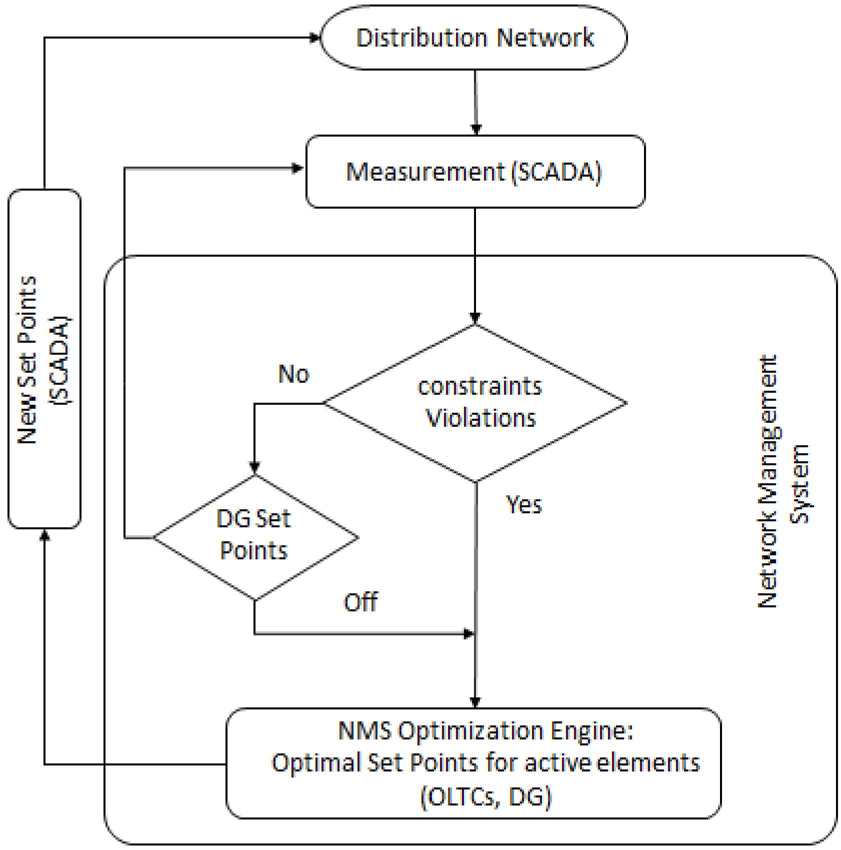

Figure 3-3 - Architecture for the proposed NMS [81].

3.3.3 Decentralised Co-ordinated control

A third control methodology, "decentralised-coordinated", involves DGs communicating with each other to identify the local states of the whole system. Information is exchanged on their particular states, planned control actions and requests to coordinate the end result of mitigating voltage rise issues in an efficient manner [75]. Local DG's communicate with each other in this control methodology to understand the state of that particular section of the distribution network. Information is exchanged on individual states, any control actions in place, and plans for control action requests to achieve the mitigation of voltage rise issues in an efficient manner. To ensure an effective voltage regulation within a local area, each voltage control device should communicate collectively. Multi-Agent System (MAS), a peer-to-peer, multiagent, synchronised control methodology has been proposed for voltage regulation applications [75]. In paper [83] discussions of the MAS concept, including definitions and example applications in the power system are presented.

3.4 Additional Methods of Control

This section initially provides details relating to control methods which traditionally have been operated on a stand-alone basis and are now starting to be considered interconnected within ANM schemes with the emergence of high speed communications on the distribution network. Demand side management is explained regarding the benefits that it can have for controlling the network.

3.4.1 Traditional control methods

Some of the traditional methods for voltage regulation include On-Load Tap Changing (OLTC) transformers to maintain the required voltage. Conventionally, measurements of the voltage and load current together with estimates of the voltage at the remote point would trigger the tap changer whenever the estimated voltage is outwith the limits [84]. Similar to OLTC, a Step Voltage Regulator (SVR) is a voltage regulator centred around a tap changer, usually located along the feeder working alongside a OLTC situated at the substation [84]. The Line Drop Compensation (LDC) control model, supplies the voltage and current at the secondary side of the OLTC transformer, estimates the load bus current and impedance of the line between the load and the transformer which in return estimates the voltage drop. The control strategy can be demonstrated in Figure 3.4 [85].

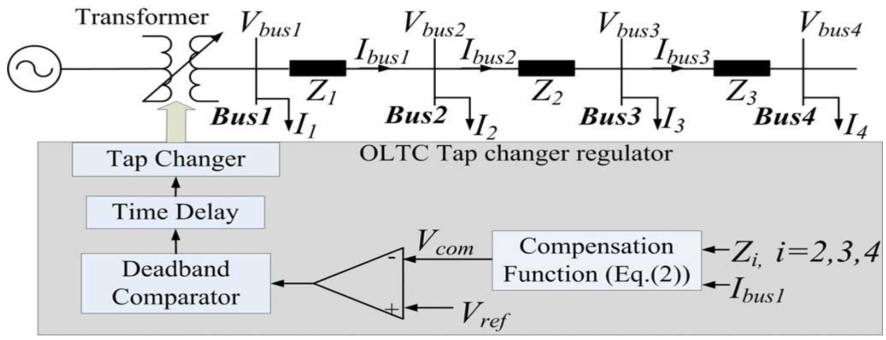

Figure 3-4 – Traditional line drop compensation control of tap changer regulator [85].

The function for the compensation voltage (V_{com}) which controls the voltage at bus 4 is given by:

$$V_{com} = V_{bus1} - Z_1.I_2 - (Z_1 + Z_2).I_3 - (Z_1 + Z_2 + Z_3).I_4 \qquad (3.1)$$

where V_{bus1} is measured on the secondary side of the transformer, load bus currents I_2, I_3 and I_4 are estimated and line impedance Z_1, Z_2 and Z_3 are obtained from network data. Voltage control of bus 4 can be provided at a nominal load, however, whenever variable renewables are connected, this control scheme may no longer work effectively due to the complexity of predicting the new load currents [85]. This problem can be overcome by incorporating communication links and transferring control to a centralised approach. The real-time load current and bus voltage data is transmitted to a central controller at the substation, which then has all the information required to maintain voltage profiles within the limits along the entire feeder.

3.4.2 Demand side management

Demand side management (DSM) and the related approach of demand side response (DSR), has emerged as one of the key methods to transform the power network into a more efficient smart grid. DSM is generally focused on long term regular adjustments to consumption and generally controlled directly by the DNO or as a result of need to constrain demand at very high peak levels, such as ‘triad’ periods. DSR is generally more dynamic and aimed at encouraging end users to make short term reductions in energy demand in response a trigger from the network operator or a price signal from the market. Typically DSR is for a short time period and is more dynamic and market based. Financial incentives and behavioural changes through education are two methods in which to roll-out DSM/DSR. In this sub-section, the drivers behind the development of DSM/DSR alongside the benefits and opportunities are discussed. Finally, a brief explanation of the DSM techniques are presented.

<u>Drivers</u>

Development of demand side management has been taking place for over 30 years, however, only in the last 5-8 years has additional research has been undertaken to demonstrate its advantages as an alternative to investment in generation and electricity networks [86]. With growth in renewable generation, an approach to provide a secure network is required, and DSM is perceived to be an answer. Larger non- domestic consumers already provide demand-side response (DSR) services to a range of market participants [87]. The roll-out of smart metering could be open up the service to a wider range of customers, plus the transition to electrification of heating and transport could provide more flexibility for customers using electricity. Finally, other incentives such as reducing bills, enhancing security of supply and contribution to a more sustainable power system are major drivers for DSM/DSR [87].

<u>Benefits and opportunities</u>

DSM can provide some of the long term reserve which would historically be met by stand-by from generators. This is an alternative method of delivering security of supply. Identification of consumers that would, for a fee, be willing to be disconnected or have consumption reduced from the network on occasion. Reduction in transmission and distribution network investment is achievable with DSM. As demand increases year on year, DSM could limit the maximum demand to allow the use of existing assets, thus saving from infrastructure reinforcement costs.

DSM Techniques

Peak load shifting allows the DSM to change the time pattern and/or magnitude of consumer's demand by encouraging users to consume less electricity during peak times, or shift their energy use to off-peak hours to smooth out the demand curve [88]. Another more desirable action is to follow the generation profile, however, in either case, there is a requirement to 'control' the consumer's energy use. DSM will therefore play a pivotal role in electricity balancing and contribute to increasing the efficiency and use of system assets. Several methods to achieve peak load shifting are described in [88]; all methods are targeted at using price signals to provide positive results.

Current DSM Activity

There are several DSM trials and concepts which are at an early stage but if proven to be successful, could easily be expended to larger schemes to provide the flexibility that an active distribution network requires. The NINES project aims to use DSM and a large thermal boiler, domestic energy storage heaters and advanced water heating cylinders to adjust the use of electricity at times when the network in Shetland is overloaded or too low and there is surplus renewable generation [86]. The target is to use direct control of the technologies connected to the grid. A smaller project established by the residents of Fintry, a community project based in the Stirlingshire village of Fintry, Scotland to develop a new way of trading and charging for electricity. This will allow local householders and businesses to buy their electricity directly from nearby renewables, using the existing distribution network infrastructure. The aim from the community is to reduce both electricity costs and carbon impacts [89]. However, the concept shall enable the balance of demand and generation, the cost for electricity will reduce when surplus electricity is being generated, prompting the community to consume. Whereas, when there is no renewable generation available and the demand is near peak, the cost will increase to towards maximum and will deter the community from consuming electricity, if possible. Ultimately this will reduce maximum demand in the area.

3.5 Risks and Benefits of Active Network Management

This section examines the possible risks and benefits associated with the implementation of active distribution network management. The main benefits of ANM is preventing infrastructure reinforcements [63] and allowing greater capacity of DG to be connected to the distribution network, whilst maintaining a secure, safe and reliable network operation [90].

Centralised and Co-ordinated active management control techniques utilise measurement, communications and coordination facilities to regulate assets connected to the distribution network. There are several advantages against the alternative decentralised strategies. Firstly, detection of network constraints will be immediate and precise. For example, an enhanced visualisation of critical points throughout the network can be realised using real-time monitoring throughout the network. This can be advantageous to overcome voltage problems which would otherwise be overlooked with traditional Automatic Voltage Control (AVC) systems within substations.

Secondly, amid development of centralised and co-ordinated ANM approaches, the monitoring and communication arrangements can be fully extended and adaptable to include future connections and advances in DG [91], even in remote areas of the network most suitable for harnessing renewable energy. This is advantageous over decentralised network management. Power reliability and quality is likely to be improved through the communication infrastructure required for "smart grids" [92].

The key risk associated with centralised and co-ordinated ANM schemes are the reliance on monitoring devices and communication links. The dependency on the equipment is paramount and a single point of failure could bring the whole system down. The quality, reliability and robustness of the communication medium (e.g., lease fibre, private wire, telephone lines, satellite and mobile radio) is paramount and channel capacity (from a few hundred to a few thousand bits per second) is essential [91]. This creates a challenging issue for security of supply [92] and may make it necessary to provide back-up systems which could be utilised during loss of data processing or communication links; however, this could prove too costly to have redundancy for such occasions on every area of the network.

Decentralised control in contrast, only utilises local information to independently control voltage at a specific bus. In all likelihood, this will reduce the upfront costs due to the limiting of monitoring, optimisation and communication systems. No or limited advanced communication requirements are necessary between a central controller and the DG, therefore eliminating the risk of the system collapsing due to a single point of failure as only the individual asset would be disconnected from the network. However, the performance of a decentralised control scheme will likely be limited in comparison to the centralised and co-ordinated systems, but ought to provide satisfactory responses to control the network constraints within the local area. This is a trade-off that the DNO and developer of the DG have to take into consideration at the planning stage.

In terms of financial viability, developers may prefer the more economic approach of decentralised control with the limited communications and monitoring equipment required, hence keeping the cost down. In some instances when the constraints are difficult to manage utilising decentralised control schemes, it may be beneficial to incorporate a centralised method with enhanced control performance and this may outweigh the increased capital investment. Each individual development requires examination of the potential benefits and risks associated with investment, operational performance and network compatibility before adopting a control strategy.

Several trials of ANM have been successfully deployed across the UK. Most notably are Scottish Hydro Electric Power Distribution's (SHEPD) Orkney scheme [93], Scottish Power's Accelerating Renewable Connections (ARC) project [94] and UK Power Networks (UKPN) Flexible Plug and Play project [95]. The trials have been funded through the electricity Network Innovation Competition (NIC) and successfully demonstrated that ANM in some instances can defer the requirement for network infrastructure reinforcements and permit additional DG connections controlled under an ANM arrangement. Under funding requirements, DNOs are compelled to the best of their ability to take technology to a full system roll-out. The

Electricity Network Innovation Competition Governance Document, Condition 1.10 states [96]:

> *"All electricity customers fund Electricity NIC Projects. A key feature of the NIC is the requirement that learning gained through Projects is disseminated in order that customers gain significant return on their funding through the broad roll-out of successful Projects and the subsequent delivery of network savings and/or carbon and environmental benefits. Even where Projects are deemed unsuccessful, Network Licensees will gain valuable knowledge that could result in future network savings."*

Listed below are some of the challenges that exist in roll-out of ANM into business-as-usual (BaU) and include [97]:

- What is the trigger for ANM deployment?
- How will the capital costs be recovered?
- What form will the contracts for managed connection take?
- System design methodologies will require adaption to be able to simulate ANM system behaviour;
- Approximation of expected curtailment must be provided to the customer;

The above challenges alongside many more will require tackling to ensure that roll-out progresses smoothly.

3.6 ANM Activities in the UK and Europe

Industry has trialled and tested a range of ANM models on small sections of the distribution network. Particular methods have been commissioned and initiated in areas that have major issues with network constraints. ANM schemes have advanced in the last 2 or 3 years with the need for actively managed connections becoming increasingly sought after. The majority of the developments are concerned with voltage control and line flow management issues. These can be sub-categorised into ANM strategies discussed in Section 3.3, i.e., centralised, decentralised and coordinated control. This section will briefly discuss several ANM activities currently engaged within the UK and worldwide, including applicable results for voltage control and line flow management which this thesis primarily embraces.

3.4.1 Voltage Management

Voltage profiles on the distribution network are being altered due to the considerable levels of DG currently connected, which will only increase over time. To ease the voltage rise issues presently experienced by DNOs due to DG, a variety of methods are exploited to negate these effects:

- Replace conductor with greater current carrying capacity;
- Replace transformers with increased capacity or install additional capacity;
- Network reconfiguration;
- Installation of shunt capacitors or inductors for reactive power support;
- Reduce voltage at primary substation with active control of OLTC transformers;
- Installation of voltage regulators along DG connected feeder to reduce voltage;
- Active power curtailment of DG;
- Adjustment of DGs reactive power;
- Utilise controllable loads;
- Any combination of the above systems and tools.

The first two methods are traditionally the approach DNOs would have utilised to supply additional capacity to the network for connections of generation and demand.

These are the most cost intensive and are now considered the last resort if new innovative methods are not possible.

Centralised Voltage Management Control

The first technique network operators consider in an attempt to control voltage rise issues, is to control the tap settings of the OLTC transformers. This is described as one of the simplest tools that DNOs have at their disposal and frequently employed together with AVC relays to assist with preserving voltages downstream within statutory limits. White [98] at Econnect developed one of the first advanced automatic voltage control systems (GenAVC) to be embedded into a commercial product and utilised on the UK distribution network. It operates over a real-time control program receiving voltage values from remote terminal units (RTUs) over communication links from a few key locations on the distribution, as illustrated in Figure 3.5. The GenAVC estimates the current state of the voltage profiles at each primary substation by utilising a model of the network and the key measured voltages. Voltage limits are monitored against reference values and a control signal is sent to the AVC relay of the transformer to adjust the tap set point should the estimated voltage values come close to predefined limits. As a result of the tap change operation, all voltages would remain within the statutory limits. The state estimation is operated in real-time and updated continually to maintain the network's voltage profiles, even if generation or demand changes value. The GenAVC was trialled at an 11kV primary substation in Norfolk, UK. The results demonstrated that the device was able to maintain the voltage profiles throughout the network within the required operational limits [99].

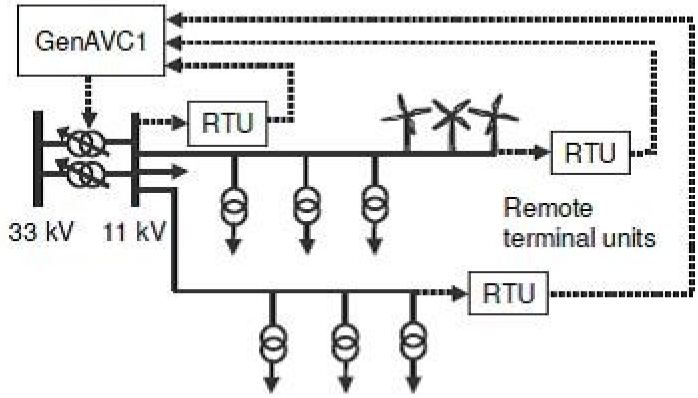

Figure 3-5 – Example GenAVC system on an 11kV network [98].

Electricity North West through their Customer Load Active System Services (CLASS) project demonstrated a low cost, rapidly deployable solution for active voltage management. The project was funded through Ofgem's Low Carbon Networks (LCN) second tier funding mechanism. CLASS provides an array of demand response capabilities and network voltage regulation services [100]. The scheme will support the UK's ambition of reducing carbon emissions, driving towards a low carbon economy and minimising the potential of requiring costly network reinforcements.

An Autonomous Substation Controller (ASC) designed by Siemens is operated at each primary substation to control voltage [101]. It works by sending signals to AVC schemes already in place at the substation. The AVC operates as normal but only responds to tap change controls when prompted by the ASC. The scheme functions through a mixture of central dispatch and local control. To manage voltage profiles the CLASS system works together with the Power on Fusion (PoF) NMS approach. The RTUs located at the primary substations have been reconfigured to interface between the NMS and the voltage controllers. Demand response actions will either reduce or increase demand to balance the change in generation from wind farms. Reduction in NGET transmission system voltages are provided by the means of staggered tap position between parallel transformers. Finally at times of system peak at primary substations the demand will be reduced by way of supply voltages.

Figure 3.6 displays the functional arrangements of the ASC. One of the main functions of the ASC is local voltage management and this is achieved by communication between RTUs and ASC to operate the OLTC transformer tap position to affect voltage changes. Maintaining the demand below each primaries' capacity will defer network reinforcements.

A second function is reactive power management which aims to control (capacitive) voltage rise on the transmission system. This becomes an issue on highly capacitive transmission networks, especially while low loading occurs. In this scenario, the ASC deliberately operates the parallel transformers with different tap positions creating additional VArs to be absorbed from the higher voltage transmission network than are consumed on the load side. It uses the transformer's leakage reactance to let current circulate between the two transformers. When a call is issued, the transformers are operated with a stagger to draw extra VArs, which in turn assists in maintaining control of voltages on the transmission network.

Parallel transformers are categorised into three stages of absorption and the TSO calls in order of relative Var requirement: (1) "High Var"; (2) "Mid Var", and (3) "Low Var". A calculation of MVars are achieved through the tap staggers and is approximately equivalent to between 3 (10% absorption) and 1 (5% absorption) tap changes. Negative effects of tap staggering include overloading of the transformer and subsequent heating of the windings, potential hotspots can involve contact failure and worse case can cause degradation.

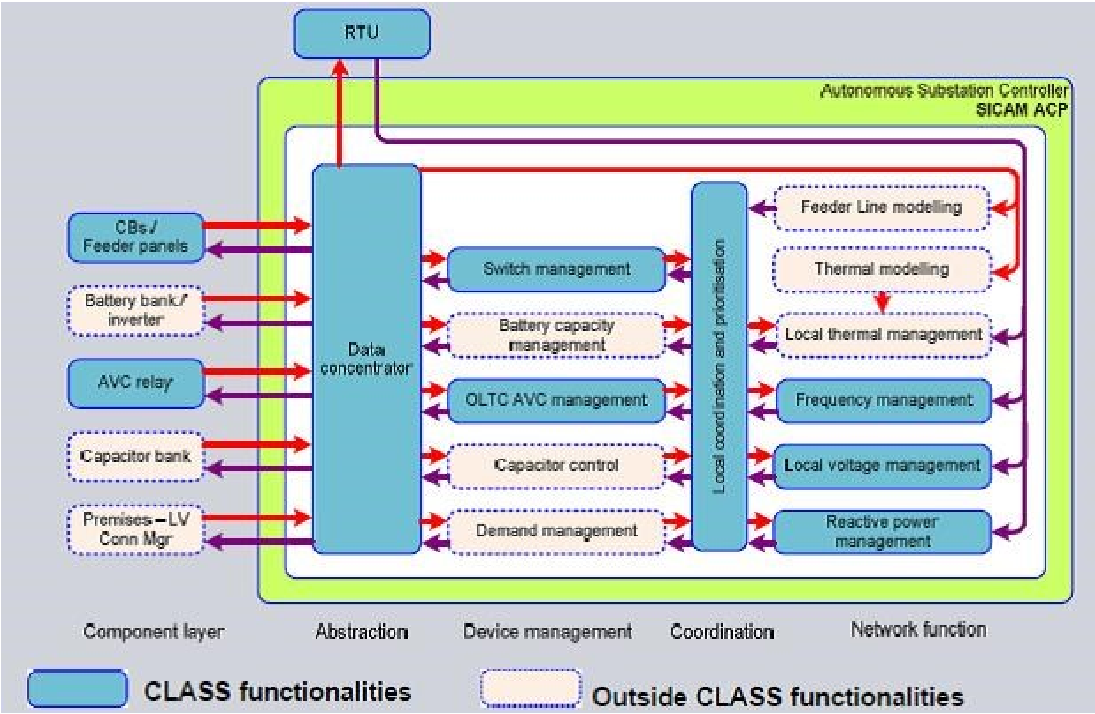

Figure 3-6 – Functional overview of the ASC employed in CLASS project [100].

Coordinated Voltage Management

As described previously, the coordinated voltage management techniques are a hybrid of centralised and decentralised schemes. They involve some monitoring at specific locations to control the OLTC transformer to maintain the voltage profile at the point of connection within the statutory limits. The Automatic Voltage Reference Setting (AVRS) technique developed by Li and Leite [102] and shown in Figure 3.7, focuses on providing a reference setting for the AVC relays and OLTC transformers to maximise the volume of connections of DG. Two or more important voltages are measured to allow the AVRS technique to compare the maximum and minimum values against the voltage limits of the feeder. A new voltage reference (*Vref*) is then calculated by [102]:

$$V_{ref}(new) = V_{ref} + f(V_{ref}, V_{up_{limit}}, V_{lower_{limit}}, V_1 \dots V_m) \qquad (3.2)$$

where $V_{ref}(new)$ is the new voltage reference setting for the AVC relay, V_{ref} is the AVC relay's current voltage setting, f is a function of V_{ref}, $V_{up\ limit}$, is the feeder voltage upper limit, $V_{low\ limit}$, is the lower feeder limit and (V_1 ... V_m), are the essential remote voltage measurements. The remote measurement points are located at points on the network where either the maximum or minimum voltages are expected to occur.

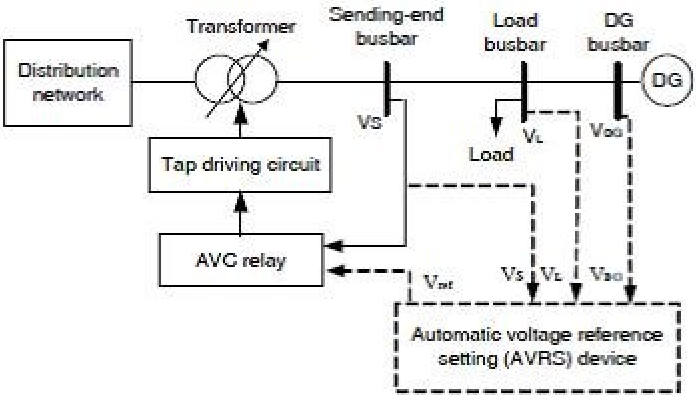

Figure 3-7 – A basic feeder example with AVRS voltage control system [102].

Decentralised Voltage Management

Control algorithms employing local voltage management have also been developed. The Advanced Compensation Voltage Strategy (ACVS) technique developed by Gao and Redfern [103] is an extension of the Line Drop Compensation (LDC) scheme. Conventional LDC schemes assume that power flow is only in one direction as illustrated in Figure 3.8.

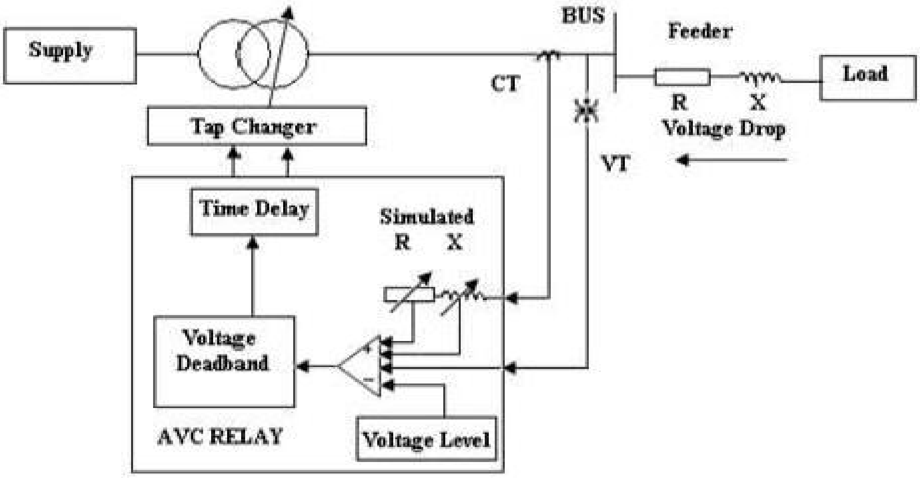

Figure 3-8 – A typical AVC relay scheme with LDC [103].

The ACVS, however, accommodates line voltage rise alongside line voltage drop at remote locations without the requirement of any communication links. The technique works by modelling the voltage profile of the bus with the DG connected to them. When a small amount of power is exported, the current will remain in the same direction as expected with no DG. A medium to large scale DG will cause the current to reach zero then reverse in the opposite direction. The ACVS changes the voltage reference point according to the transformer's current direction. The new control method considers power flow to manage integration of DG, as demonstrated in Figure 3.9.

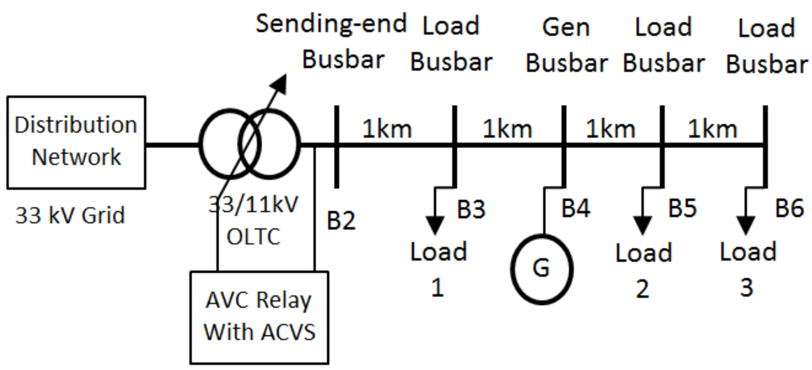

Figure 3-9 – A single line of an 11kV distribution network with DG and AVC relay with AVCS scheme [103].

Power Flow Management

Dolan *et al.* [104] established a novel optimal power flow (OPF) method for automatic power flow management (PFM) to enable management of thermal constraints on the distribution system. The method employed is an OPF-LIFO approach, as (Last-In, First-Out) arrangements are currently being applied by the U.K. DNOs with current ANM techniques. The OPF formulation typically seeks to minimize system operation costs. True costs of operating a unit are provided due to its vertically integrated system operation. The objective function is:

$$\min_{P_g, Q_g, V, \delta} \sum_{n=1}^{N} \Omega_{gi}(P_{gi}) \tag{3.3}$$

where Ω_{gi} (P_{gi}), is the cost or offer function of a generator at bus i and it is subject to power balance equations, generation and thermal limits. A comprehensive description can be found in paper [C]. The OPF-LIFO method is based on the basic OPF model with the only change being the individual generation cost terms formulation, the order of the generators in the LIFO stack is taken into consideration. The generators connected first are assigned a cost per unit which reflects in the connection order. The highest cost is awarded to the last DG unit to connect, this allows the OPF-LIFO approach to issue an instruction to constrain (see Figure 3.10) to last unit to connect, similar to other LIFO arrangements.

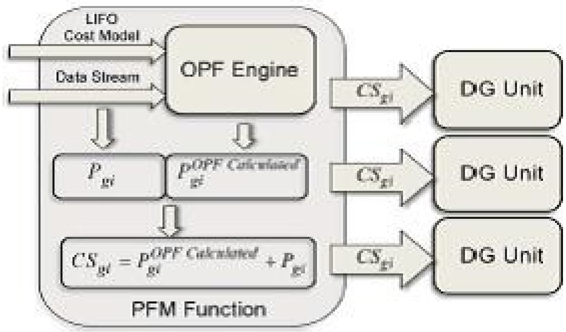

Figure 3-10 – Concept of OPF-LIFO control and computation scheme [104].

Multi Constraint Management

The Autonomous Regional Active Network Management System (AuRA-NMS) is an ANM scheme focusing on real-time control algorithms for voltage control, power flow management and restoration [63]. AuRA-NMS was a research consortium comprising seven universities, two DNOs and ABB [105]. Automation of power flow management, voltage control and restoration were investigated by partner universities with contribution from the DNOs. Utilisation of ABB's distributed computing platform COM6xx substation computer completed the input from the consortium partners.

The power flow management system had several approaches investigated but it was a constraint programming (CP) based approach [106] that was developed. It involved modelling the power flow management problem as a constraint satisfaction problem (CSP). A number of discrete values can be contained within the variable, such that solving the CSP provides a discrete value that does not violate the pre-defined constraints. The constraints cover contractual constraints such as network access rights ("the queue") and power flow constraints. A preference solution is set to meet power flow and contractual constraints but maximise DG access. The COM6xx was integrated with an off-the-shelf CSP solver and load flow engine as demonstrated in Figure 3.11. Real-time network data is applied to update the network model.

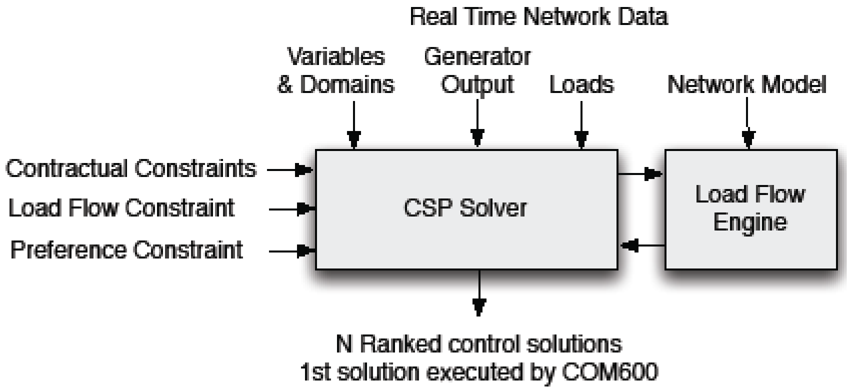

Figure 3-11 – Software for CP approach to power flow management [105].

Two approaches were developed for the voltage control aspect of the AuRA-NMS programme. Firstly, a CP method adapted from the power flow management scheme, with a voltage constraint to maintain voltages within statutory limits. Secondly, a case-based reasoning (CBR) approach was developed, for identifying possible voltage control solutions [107]. Figure 3.12 illustrates a modified CBR system for voltage control operation. In general, four subsections are contained within a CBR system: (1) using the case base library, recover the most closely matched case with the greatest similarities; (2) Reuse the cases and attempt to solve the current problem, adaptation if necessary; (3) Revise the proposed solution if required; (4) Finally, keep hold of the new solution as a new case.

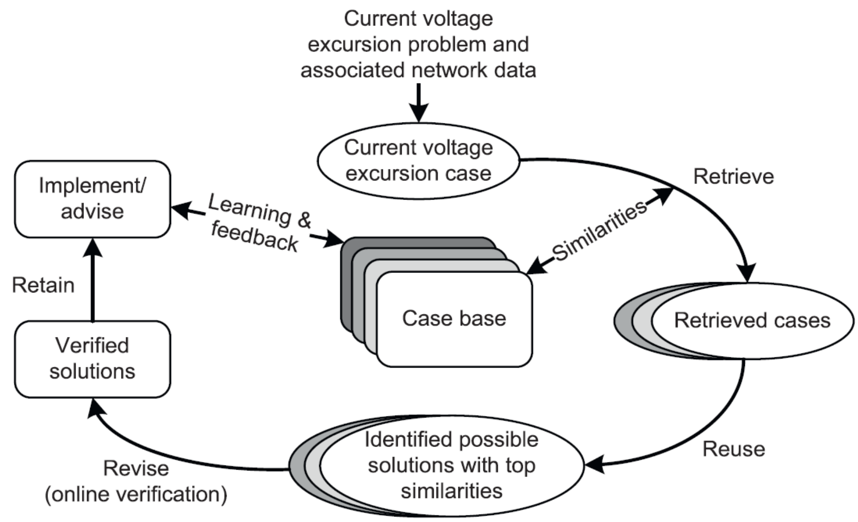

Figure 3-12 – CBR approach for voltage control management [107].

3.7 Smart Grid

This section describes the concept of smart grids and gives a brief description of some current activities in the UK and around the world.

3.7.1 Concept of smart grids

Often confusion can be experienced when the expression “Smart Grid” is contemplated. Firstly the term “smarter grid” is sometimes used to explain a “smart grid” but these are two different ideas. The “smarter grid” is a transition towards a “smart grid” in which the network functions in a more efficient way, allowing for a level of service which consumers have come to expect at a reasonable cost and offering societal benefits, for example, less of an impact on the environment. The “smart grid” will transform the power system in a similar manner that the internet has expanded and developed over the last decade or so and impacted on the way in which we live, learn, play and work [108].

Smart grids are networks which are consumer interactive as opposed to the current generator-controlled set up. The progress towards a smart grid will alter the industry’s entire business model and interaction with stakeholders, regulation and technology. Smart grids comprise various active components which interact with one another and support the realisation of utilising spare capacity that the network has to offer for additional DG connections. The active components include digital monitoring, communications, control technologies, demand side management, energy storage and automation which provide the network operators with tools necessary to effectively and dynamically operate the power system. Active Network Management is perceived to be one component of the smart grid revolution. The transfer of system information between stakeholders require a comprehensive communication and monitoring system such as SCADA alongside other sensors and monitors, such as RTUs, required to be extensively expanded throughout the distribution network. The conceptual design of a smart grid presented in Figure 3.13 contains all the stakeholders required, i.e. consumers, service providers, electricity markets, generation, transmission and distribution operators together with management from the system operator. Consumers will also be able to make more informed decisions regarding their energy use with the information supplied by smart grids with the “roll out” of “smart metering” which will be complete by electricity suppliers by 2020 [109].

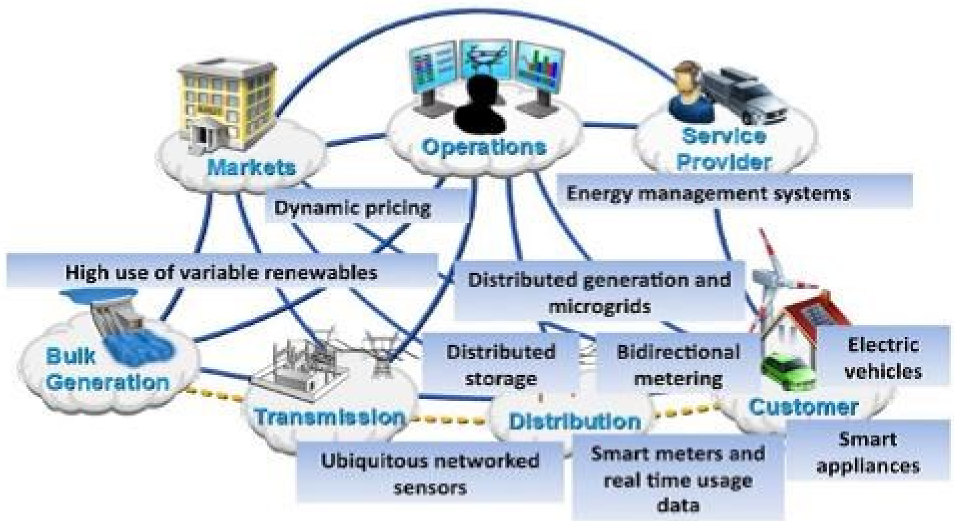

Figure 3-13 – Conceptual model of the smart grid [110].

The drivers for the electricity industry to transition towards a smart grid include [111]: improving reliability, efficiency and safety of the distribution network through actions towards decreasing peak demand; increasing flexibility of power consumption to match generation from intermittent renewable generation; permitting homes and businesses to act as both an electrical energy client (when consuming) and an electrical energy supplier (when producing), a concern regarding the first driving factor that connected load to the network vary quite significantly over time.

The UK Government's Department for Energy and Climate Change (DECC) via the Smart Grid Forum (SGF) developed a Smart Grid Vision and Routemap [112]. The vision for the Great Britain smart grid is [112]:

> "*A smart electricity grid that develops to support an efficient, timely transition to a low carbon economy to help the UK meet its carbon reduction targets, ensure energy security and wider energy goals while minimising costs to consumers. In modernising our energy system, the smart grid will underpin flexible, efficient networks and create jobs, innovation and growth to 2020 and beyond. It will empower and incentivise consumers to manage their demand, adopt new technologies and minimise costs to their benefit and that of the electricity system as a whole*."

The SGF believe several benefits and opportunities are available from smart grids and these include: reduced costs to consumers through savings on network costs by enabling consumers greater control of their energy use and receiving benefits from load shifting away from peak times; supporting economic growth and jobs by allowing quicker and less expensive connections, therefore, increasing the number of developments to progress through to construction; finally increase energy security and volume of low carbon technology integration by utilising the advanced monitoring and control of the network.

3.7.2 Smart grid activities in the UK and worldwide

Smart grid technologies in the UK are at different stages of deployment. One element of a smart grid, active network management is currently being utilised within small sections of the distribution network to control a number of network violations, including voltage and power flow constraints. Other areas have not progressed as quickly and a whole smart grid system approach is some time from becoming a reality. In saying that, some DNOs have started and in some cases completed innovation projects with a whole system approach in mind. In this section some of the projects will be briefly explained and outcomes, if any, presented.

Northern Power Grid's innovation project, Customer-Led Network Revolution (CLNR) supported through the Low Carbon Network Fund (LCNF) considered consumer and network-led flexibility options in managing the distribution network. Features included in the project: domestic use of time tariffs which enable consumers to make economic choices of when to use electricity depending on the cost; industrial and commercial demand side response (DSR) which permits agreements between the DNO and consumer to reduce demand usage at times of peak demand; storage allows electricity to be stored and utilised at times of peak demands, when perhaps generation would be short of meeting demand; domestic heat-pumps; electric vehicles; rooftop PV; and smart washing machines which all provide energy efficiency measures, demand reduction and the ability to switch off/reduce demands in an autonomous manner. The key finding from the project suggested that smart grid control systems can resolve multiple constraints amongst multiple assets [112].

The European Technology Platform for the Electricity Networks of the Future (ETP SG) was formed in 2004 during the first International Conference on the Integration of Renewable Energy Sources. The initial concept and guiding principles of the ETP SG was drawn up in 2005, with the aim to "formulate and promote a vision for the development of European electricity networks looking towards 2020 and beyond" [113]. Currently three ETP smart grids working groups exist [114]:

- Working Group 1 – Network operation and assets:
- Working Group 2 – Energy storage and grid integration;
- Working Group 3 – Demand side, metering and retail.

Nearly 20 countries throughout Europe are involved in smart grid initiatives through the ETP SG framework ranging from smart metering to storage, integration of renewables to regulations and much more. The national SG platform in Spain, FutuRed have several flagship projects in the subject of smart grids. Most notable the PRICE project led by Iberdrola and Gas Natural Fenosa (two leading network operators) aimed to answer the technological challenges regarding the next generation of electrical systems which are required to utilise existing ageing infrastructure and incorporate the growing numbers of electric vehicles (EV) and improve the security of supply. Some 73.3MW of wind and PV energy was utilised to demonstrate that monitoring and automating the MV/LV distribution network could allow improved operation and maintenance [115].

Denmark's National SG Platform, PowerLabDK goal is to support sustainable energy. Secure Operation of Sustainable Power Systems is a research and development project providing real-time assessments of system stability and security. Investigation into an intelligent 'wide-area prosumption' control method is aimed at changing the system prosumption patterns over a short period of time. This is carried out by changing set points for controllable loads and DG to determine whether stable and secure operation can be achieved [116].

Elsewhere in Europe, a project investigating a smart grid for the city of Rome was completed through the European Commission's Joint Research Centre (JRC) in 2015. It examined whether investing in smart grids was worth the cost. Smart grids are often believed to be a solution that is still in the testing stage but that will come to commercial maturity at a future time [117]. Due to the increased complexity of interactions between stakeholders, a prompt technique is required to ascertain who pays the cost of maintaining the emerging distribution. [118] introduced a "market-based control" mechanism for recovering those costs. This project likewise was established in Italy and aimed to set price signals by macroplayers (DNOs, TSO, regulator and retailers) for optimising system performance set by predefined objectives through stimulated prosumer actions. The author asserts that by incorporating "market-based control" into network charging, improvement to the overall performance of both the market and network can be achieved [118].

In the US, the American Recovery and Reinvestment Act (ARRA) has invested US$4.5 billion into smart grid development [119]. This is required due to the lack of investment over the last few decades in the expansion of the transmission and distribution systems and smart grids are perceived to be an alternative to major infrastructure reinforcements. To be eligible for funding the smart grid projects must be appropriate within one of the following six categories, some examples are included below [119]:

- Advanced Metering Infrastructure (AMI) – installation of domestic smart meters to enable dynamic domestic energy pricing;
- Customer Systems – development of systems for automated peak pricing response for approximately 700 commercial and industrial customers;
- Electricity Distribution Systems – deployment of monitoring, automation and communications systems on their distribution network to improve self-healing capabilities and distributed generation integration;
- Electricity Transmission Systems – deployment of phasor measurement units alongside a systems-wide open communications system;
- Equipment Manufacturing – development and commercialisation of smart appliances capable of communicating over a home-area network with smart metering in order to defer energy use to periods of low pricing;
- Integrated and/or Crosscutting Systems – build a virtual power plant (VPP) across a smart grid, including installation of over 160,000 smart meters.

3.8 Distribution Network Planning with Active Control

Increased quantities of renewable DG are being connected to the distribution network and due to the variability of generation, increasing levels of uncertainty is being experienced [120]. DNOs are still following traditional planning arrangements, despite the DG revolution. The shortage of new planning tools that can deal with future scenarios have been blamed for DNOs lack of willingness to use modern planning techniques [120]. In recent years, work is underway to develop new planning schemes which can prove the benefits over traditional methods.

Keane *et al.* [121] reported the findings of, an IEEE task force on distributed generation planning and optimisation as a critical review of the work in planning and optimisation of the distribution network. Although published in 2013, the paper is still applicable now, as wide-spread implementation of the advanced techniques have still not taken place. The various state-of-the-art techniques described are categorised into six different approaches as Table 3.2 shows:

Table 3-2 - Summary of Planning and Optimisation Techniques/Objectives [121].

Techniques	**Objectives**
Analytical	Power losses
Exhaustive	Multiple objectives
Linear programming	Minimisation of curtailment cost Maximisation of DG capacity Maximisation of wind energy Optimal curtailment allocation
Optimal power flow	Power losses Maximisation of DG capacity Minimisation of energy losses
Metaheuristics	Maximisation of DG capacity Investment Planning Multi-objective
Probabilistic analysis	Improved reliability

The techniques discussed in [121] are largely aimed at optimisation for maximisation of DG capacity or to minimise energy losses and curtailment, very few techniques were intended for network or investment planning. This suggests further that work is required on new distribution network planning techniques. A small number of approaches are presented in the remainder of this section.

Reliability, line losses, voltage profile and load growth are considered in the optimal distribution network planning methodology introduced by Ziari *et al.* [122]. A hybrid optimization method employed is utilised to solve a nonlinear problem which considers both traditional reinforcements and the use of DG to meet growing demand growth. An important factor is loss reduction which can postpone the need to upgrade high voltage transformers. Capacitors are commonly used to reduce line losses and improve the voltage profile by reducing the reactive component of the feeder current.

A multiyear distribution network planning optimization model has been developed by Mohtashami and Strbac [123]. It compares two different planning approaches: (1) strategic; and (2) incremental; alongside an AC OPF algorithm to optimise network reinforcements. Its purpose is to maximise the use of existing assets and actively manage the real-time operation of the network. The aim is to balance the capital costs for reinforcements with the reduction of the operating cost. This differs from other models by considering traditional reinforcement options alongside DG:- ANM, transformer tap settings and Static Var Compensation (SVC) are all optimised to manage thermal and voltage constraints. Location of DG is considered when more than one option is available to reduce system costs in the long term. The results demonstrated that the incremental approach favours smart technology which provides a lower short-term costs but, in the end, increases the long-term costs. The strategic investment approach minimises the long-term costs but in doing so may result in greater short-term costs. The method does not include uncertainty which is vital in planning for the future with a large number of unknowns.

Giannelos and Strbac [124] have developed a novel stochastic planning model to identify optimal investment strategy that eliminates voltage rise effects triggered by increased penetration of DG. While including firm DG, quantification of the option value of smart technologies, such as, Coordinated Voltage Control (CVC), Soft-Open Points (SOP) and Demand-side Response (DSR) are considered alongside traditional reinforcements. Decisions to invest in either traditional reinforcements or smart technologies use the results from a stochastic optimisation-based valuation tool. Considerations of load and wind farm uncertainties are omitted from the stochastic planning model which may provide results that are not accurate.

Falaghi *et al,* [125] presents a framework considering reinforcement options for new transformers, overhead lines or DG as possible solutions for distribution network expansion planning. A pseudo-dynamic based methodology is used alongside a developed GA and OPF optimization tool to solve the problem. The aim of the approach is to discover the minimise both the fixed costs corresponding to the reinforcement assets as well as the variable costs associated with the operation and reliability of the network. The approach uses discrete variables such as the asset location and size, to complete a search by the GA. The OPF is employed to optimise the operating costs and establishes the power generated by DG and power imported from the transmission system. The multistage expansion planning procedure is divided into two phases. In the first phase a static model is employed to determine a solution that can meet system requirements for the final year of the plan. The second phase, load growth is considered and single stage expansions of the distribution network are obtained. An optimal intermediate plan is found for each year between the base and the horizon year. Each intermediate year is analysed against the first stage plan to determine in which year the reinforcement is required. The model demonstrated that expansion planning integrating DG can results in lower costs and higher reliability. However, [125] only considers DG as owned by the DNO and this is not possible under current regulations in Europe. Therefore, the model does not fully consider the uncertainty associated with locational impact of DG.

Business cases utilising a novel planning tool for Active Distribution Networks (ADN) have been developed to prove the benefits of active networks as introduced by Celli *et al* [126]. The business cases are developed to cope with the uncertainties introduced by DG and identified that adoption of time series models are required to capture the operational aspects and calculation should be based on probabilistic approaches to capture the uncertainty experienced with actual demand and generation profiles. A multi-objective approach has been proposed to tackle the uncertain scenario that characterises the future ADN as an alternative approach to the existing single objective function of minimising cost. The results demonstrate that with the right tools more effective distribution planning solutions could be achieved. [126] also states:

> "The capability to correctly assess the value of active operation in the distribution planning is fundamental for the convincement of the DNOs to move towards the future Smart Grid concept".

This reiterates the requirement for new novel planning tools for designing active networks such as the new framework proposed in this thesis.

Decision-making involving investment in the distribution network is a difficult task, more so when ANM schemes are employed due to the increased uncertainty. MacDonald and Ault [127] present a novel mathematical optimisation model aimed at finding a least-cost network investment strategy, considering traditional reinforcements alongside the deployment of ANM schemes. Initially the problem is modelled as a mixed-integer program before applying the Benders decomposition to divide the initial problem into a binary investment problem and two operational sub-problems. Uncertainty concerning the variable nature of demand and generation is incorporated by utilising stochastic programming techniques. Paper [127] demonstrates how the deployment of ANM schemes can be integrated into existing network optimisation models.

Wang [15] presented an approach for quantifying the impacts DG have on the deferment of demand and system security related reinforcements. A two stage expansion plan was considered utilising a successive elimination technique together with a multistage planning analysis to determine required investments and scheduling along a planning horizon. Investment deferral is estimated by calculating the costs for reinforcements without DG and subtracting the cost for reinforcements with DG. The method considers system security and aims to maximise investment deferral. Results show that benefits, in terms of investment deferral are possible if the DG contribution to system security, as measured by the 'F-factor' defined in ER P2/6, is taken into account. Deferment also varies dependent on location and size of the generator. The method does not incorporate control of DG via ANM schemes, nor explicit treatment of renewable variability.

The expansion planning analysis involved a successive elimination (SE) method. Shown in Figure 3.14 is the flow chart explaining the SE procedures. The fundamental concept is firstly overbuilding the network taking into consideration the increase in demand at the end of the planning horizon. New lines and transformers are incorporated into a revised network model with increased capacity to meet the growth in demand. Examples of upgrading assets and the addition of parallel reinforcement are shown in Figure 3.15. Assets are then systematically tested by removing them one-by-one and ensuring that no thermal or voltage violations exist. The cost-effectiveness of removing each asset is then calculated. Security of supply is also considered in Wang *et al*'s version of the SE method, offering acceptable operation of the system during first circuit outage (N-1) conditions. The SE technique does not differentiate between the addition of parallel reinforcements and upgrade of assets as it solely bases its decisions on cost-effectiveness. The least cost-effective option is removed and the network updated. If for a given expansion option, a voltage or thermal constraint exists for either normal operation or N-1 security requirements, then this option's cost-effectiveness index is set very high. The cycle starts over again, the next least cost-effectiveness option is eliminated until all results of the cost-effectiveness calculations are set to a very large number. At this point the final expansion plan has been established.

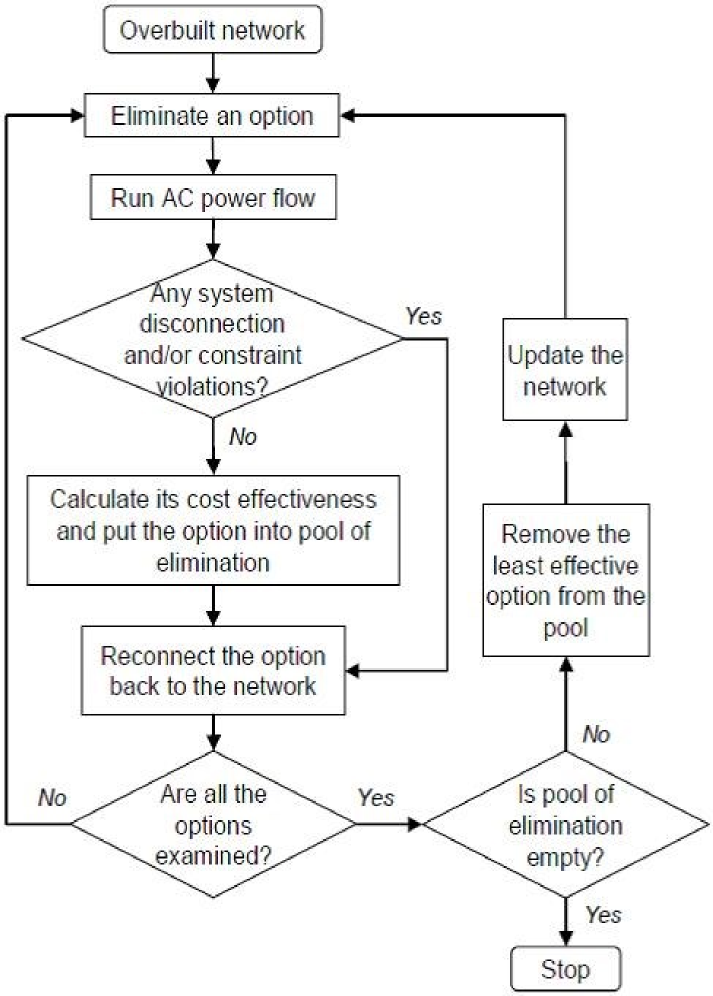

Figure 3-14 – Successive Elimination Method Flow Chart [128].

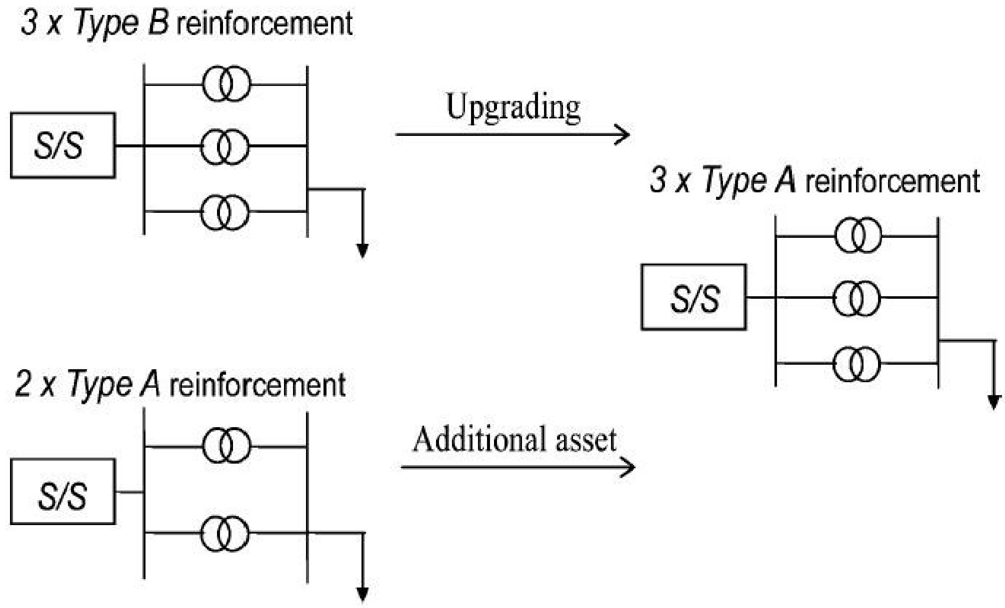

Figure 3-15 – Example of upgrading of assets and addition of a parallel reinforcement, as expansion planning options [13].

The SE method provides details of the assets that require reinforcements to meet the demand growth at the end of the planning horizon. However, it does not necessarily mean that these reinforcements are required at the beginning of the horizon. The second phase of the expansion planning analysis therefore ascertains the timetable in which reinforcements obtained from the SE method are required. Connection of DG can defer investment by offsetting the demand growth and postponing the requirement for reinforcements until further along the planning horizon. Wang *et al*'s planning analysis assumed that the connection of DG was for the duration of the planning horizon, i.e., installed in the base year. Starting at the end of the planning horizon, upgrades are assessed to determine if they are required within that year utilising the cost-effectiveness calculations. The least cost-effective upgrade is eliminated, until all remaining options are required to maintain a safe and secure system (no voltage or thermal violations) under both normal and N-1 security conditions. If voltage or thermal violations exist, then reinforcements are required and the year is decremented by one year along the planning horizon. Each load is then reduced to reflect this change in year and the process is begun again until either the original network is achieved or the base year is reached.

Investment deferral is achieved by calculating the present value (PV) cost for two planning scenarios: the first is the expansion plan without DG, and the second with DG. Subtracting the PV calculated with DG from the PV calculated without DG provides the total investment deferral achieved.

3.9 Chapter Summary

In this chapter, a summary of various different categories of distributed generation and network control systems have been given. Various active network management techniques are described in detail. Discussions of several examples of ANM activities across the U.K. and Europe have been revealed. Risks and benefits associated with ANM have been considered. Information regarding traditional and different types of control methods is presented, including demand side management which is perceived as a means of maintaining a secure network without the requirement for back-up capacity generation or network reinforcements. A definition and examples of current activities within the smart grid sector has been examined.

Actively controlled DG can create a positive effect on the existing distribution network. Additional DG capacity could be released and investment deferral achieved by monitoring and controlling DG in real-time and managing voltage and power flow constraints in a more effective manner. From the literature it is clear there is various work being undertaken in adopting the use of active control within planning. However, the specific absence of work on the uncertainty associated with renewable variability and planning of the distribution has indicated that research is essential in this subject area. The new expansion planning framework developed in this thesis, examines this aspect alongside a range of other aspects including demand growth; quantity of DG connected; the location on the network. The next chapter presents the first stage of the development of the planning framework.

Chapter 4

Enhanced Expansion Planning

4.1 Introduction

Chapter 3 suggests that active control is widely regarded as a method to enable a greater capacity of DG to be connected to the existing distribution network. However, it was demonstrated that there was relevantly limited work on bringing control within the planning approach, particularly in terms of ‘automated’ and/or optimised methods. As such, the focus of this research was to develop a planning framework that could demonstrate that actively controlling DG, at times of network constraints, could release additional headroom, which “fit-and-forget” passive design neglects. The aim was to implement a new tool that could reassure distribution network operators that control of assets is achievable when required to preserve statutory and physical design limits.

The work substantially extends previous work conducted by Wang *et al.* [13, 15, and 18] who developed an integrated planning approach considering the addition of DG as an alternative to traditional reinforcements. As an exemplar of active network control approaches, the approach additionally implements a decentralised adaptive control scheme capable of adjusting active and reactive power in order to maintain multiple constraints, i.e. support voltage at the connection bus within predefined limits and manage thermal overloads commonly found within rural networks.

This chapter provides a set of control arrangements embedded within a planning scheme designed to tackle thermal and voltage constraints. The modelling specifications and considerations for the enhanced expansion planning method are then considered prior to a full description of the control algorithms embedded within the framework. Finally, the chapter concludes with a case study employing a test network to provide a preliminary validation of the benefits from the enhanced expansion planning method.

4.2 Requirements

The work identified during the literature review was in general well founded and mostly recent. However, in developing the expansion planning framework in this thesis, the following requirements were regarded as important:

- An approach that would be sufficiently straight-forward for the power industry to follow;
- An approach that was fully auditable – not just a black box – such that details and decisions can be logged for later use;
- User friendly that needed to be readily available and trusted;
- Repeatable to inspire trust and aid interpretation;
- A modular approach capable of implementing any reasonable type of ANM scheme within it;
- Building on existing work where possible;
- The ability to capture the variability of renewable generation and demand;

The first four aspects were seen as a response to the DNOs traditionally very 'rule based' approach as well as risk aversion. This manifests itself in a need to be able to justify decisions, a reasonable need to handle worst-case situations and a tendency to avoid 'optimisation' approaches in general. The requirement to make use of existing tools was aimed at trying to speed up development but importantly employing tools that were already trusted. As such, at least partial use of industry standard software was seen to be an advantage. In operation, control systems can operate at relatively high speed, of the order of seconds to minutes while planning tends to think about years. As such, a key aim was to try and 'marry' the two time-frames in a credible fashion.

The expansion planning problem is generally regarded as challenging with its mixture of integer upgrades and the non-linear aspect of power flow. The literature showed a number of approaches employing either mixed integer linear or nonlinear methods and stochastic metaheuristics (genetic algorithms, etc.). Mixed integer optimisation approaches tend to be relatively fast but are quite opaque in terms of explaining why certain things happen and also are limited by tractability within the capability of the solvers. Breaking the problem into a series of sub-problems is common to aid with the latter issue but offers nothing for the opacity. Stochastic heuristics can be very effective at dealing with mixed integer problems, can be combined with elements of simulation as a means of defining the quality of a particular solution and can be parallelised. However, they are stochastic meaning that the result will be slightly different each time and it is common to repeat the analysis a number of times to identify if the optimal is likely achieved.

Here, the approach developed around a ‘half-way house’ method that was easy to follow and implement, was deterministic and employed as many recognisable standard components as possible. This was considered to be a good response to the requirements of DNOs whilst demonstrating sufficient novelty in an academic sense. As such, the use of a greedy heuristic (successive elimination) would serve the purpose well and the version developed by Wang *et al* was a good starting point.

The next aspect was to identify a form of ANM to implement as an example. Certainly, the use of an optimal power flow dispatch would fit comfortably within the framework but it was considered that a more decentralised effort might better fit with some of the piecemeal ANM schemes already developed. As such, the decentralised scheme for active and reactive control of DG developed by Sansawatt *et al* was seen as a credible option.

4.3 Specifications

4.3.1 Initial Developments

DNOs are currently planning the future distribution networks with passive ‘fit and forget’ planning approaches. However, with the increase in connections of DG, an actively managed planning approach is required, which will facilitate extending the life of existing assets. DNOs would gain some knowledge of the extra headroom that is currently not being utilised under current planning practices by demonstrating that actively managed DG connections could be consented without affecting the safe and secure operation of the existing distribution network. With this in mind, this research develops initial concepts of the multi-stage analysis for expansion planning by incorporating an adaptive control scheme, acknowledging that for a duration of time some curtailment or power factor control may be required to keep voltage and/or power flow within limits. This differs from previous work [13-16] by supporting the use of advanced control of DG to the advantage of network investment deferral. In addition, the present value formula can provide a monetary result for investment deferral.

The proposed enhanced expansion planning method consists of three independent sub-schemes to provide a future network planning arrangement. The first sub-scheme employs the SE method to determine the minimum network required to meet the increased demand at the end of the planning horizon. Next, a multi-stage analysis is utilised to establish what time along the planning horizon, the reinforcement is required. Finally, the PV formula is used to calculate the investment deferral achievable with the inclusion of DG as an alternative to traditional reinforcements.

4.3.2 Modelling Considerations and Assumptions

Modelling a planning strategy which integrates a control scheme for active management and executing testing and simulation studies, requires a number of features to be considered. In this research, specifications regarding the following aspects are required:

1. Power system studies;
2. Control operation;
3. Generator Type;
4. Threshold to identify constraints;
5. Demand and generation data;
6. Flexibility of the scheme.

Power system studies

The expansion planning method detailed within this thesis, is first and foremost associated with investment deferral through the ability to regulate active and reactive power of the DG unit at times when constraints occur. Without this regulation, inserting further DG onto the distribution network would trigger traditional reinforcements.

Two key methods of power system modelling and analysis, are steady-state (static) and dynamic (transient) studies. Dynamic studies are beneficial for transient stability studies for example, response to faults or large disturbances but offer very little useful information on the long-term system performance. In this context, the power system studies required for this research are of the steady-state (static) type. Most modern wind turbines are capable of adjusting their active and reactive power output in a timely manner according to predefined set points sent from some type of controller [129]. This allows the embedded control mechanism within the planning strategy to demonstrate control of the DG unit.

The approach was initially developed to operate with a small number of worst-case scenarios (e.g. maximum demand-minimum generation) to keep the computational time to a minimum. In Chapter 5, the method is further developed to accommodate the variability of wind power and demand manage the constraints in a 'real-time' manner and over a continuous period.

Control operation

Within the enhanced expansion planning method, the control operation follows a set of principles that reset after each iteration, as no DG is actually being managed. The adaptive control scheme developed by Sansawatt *et al* has been simplified to remove operation of thresholds and target values; they can feasibly be incorporated. The main objective is to demonstrate that actively controlling the DG and calculating set points to maintain the thermal and voltage values within the limits can ultimately mitigate network constraints. This will provide DNOs with an improved picture of how an actively controlled network could operate and thus, lead to a better prospect of approving additional DG connections and relying less on traditional reinforcements. Network losses are not considered within this analysis to maintain the continuity for comparison against Wang's model. Further details will be presented in the limitations section of this thesis.

Generator type

The type of generator will require great consideration to allow the control scheme to manage the line overload and voltage rise locally. In practice, the generator will be required to adjust in a timely manner its active and reactive power if so instructed by the control scheme. If the generator fails to reduce its output a control signal would be sent to the local protection device to disconnect the generator from the network. This is required due to the possibility of the DNO being penalised if voltages are out-with statutory limits or damage being instigated by increased power flows. This may cause problems for DNOs in meeting local demand and requires further investigation. Within the approach considered here this is regarded as out of scope.

Threshold to identify constraints

The adaptive control scheme is activated when voltage rises or drops outside the 6% limit or the power flow exceeds the defined capacity of the overhead line rating. As mentioned previously, threshold and target values are not required within the new expansion planning framework, and a limit matching the statutory and physical limits will be used to demonstrate the sensitivity analysis being processed. A threshold value would, however, be required in the real world to handle real-time variation where the delay in curtailment could see voltage and thermal violations occur. The objective of this is to demonstrate that actively controlling the DG unit can maintain voltage and power flow within the predefined limits.

Demand and generation data

The planning strategy detailed in this chapter is based on four extreme scenarios: maximum generation/minimum demand; maximum generation/maximum demand; minimum generation/minimum demand: minimum generation/maximum demand. DNOs currently use the first scenario as the standard approach for distribution network design, including for new DG connections. DNOs are not permitted under current regulations to own or operate DG, therefore, uncertainty plays a major part in network design as no knowledge of the level of generation expecting to connect to the distribution network is known until an application is submitted. For this reason, the enhanced expansion planning method considers a number of generation values starting at 0MW and increasing in increments of 5MW up to and including 60MW for the test network described later.

Also developed and explained in Chapter 5, realistic demand and generation data is incorporated into a time series model to demonstrate that for only a small percentage of the time, do the extreme scenarios actually exist. Therefore, current planning strategies may be triggering reinforcements that are fully utilised for a few hours or days of the year.

Flexibility of the scheme

The enhanced expansion planning method is flexible and could be applied any type of distribution network i.e. meshed and radial, any size and complexity. The control scheme embedded within the new planning strategy is decentralised and has simple control procedures with only a limited number of setting options. This brings the opportunity for the scheme to become more flexible.

The planning method has been implemented in Python interfaced with PSS/E for load flow studies creating an autonomous model. The software tools are commonly found in academia and industry, therefore, presents an opportunity for future development, implementation and testing. With the increase in smart-grid technologies, the flexibility of the planning strategy provides an advantage for coordination between them.

Although previous work by Wang and Sansawatt were developed in PSS/E, the implementation combined PSS/E calling python. Here, the approach has been completely redeveloped and reconfigured such that Python drives the code and PSS/E is in effect, a plug-in. This facilitates the use of other commercial load-flow software programs.

4.4 Enhanced Expansion Planning Method

4.4.1 Problem Formulation

The problem of distribution network planning with a multi-year horizon has been modelled considering the following factors:

- The objective function is to minimise the net present value of reinforcement costs $C_{l,}$ over planning horizon T;
- The planning horizon T is divided into years. Within each year there are m ($\in M$) periods which could be hours or some aggregated representation;
- The investment cost is given solely by the capital cost, required for adding/re-conducting overhead lines or installing parallel transformers, the discounted value applies within the objective. Operation and maintenance are omitted;
- The distribution network is composed of busbars b connected via branches l (a combination of overhead lines, cables and transformers);
- Options for investment are limited to those that increase flow capacity on existing routes. These include adding transformers in parallel with existing assets with capacities that are standard and predefined. Circuits are restricted to overhead lines (although cables could also be included) and upgrades to these include re-conductoring with a predefined set of conductors of larger cross section or the addition of a parallel circuit of predefined capacity;
- Distributed generation location, capacity and possession of ANM capability is predefined for each analysis;

- Limits on conductor capacities, transformer capacities, voltage profiles and availability of DG is taken into consideration during every year and within the year along the planning horizon.

The multi-stage, multi-period mixed integer non-linear formulation minimises the total investment cost C_l of a vector of upgrades Z_l across the set of planning horizon T within year period m, according to the following objective function:

$$\min \sum_{l \in L} C_{l,t} \, Z_l \tag{4.1}$$

Here t refers to the year of upgrade and m represents a period of time within each year. It is subject to a range of constraints. Voltages at bus b (B, set of buses) are constrained by maximum and minimum levels $V_{b,min}$ and $V_{b,max}$:

$$V_{b,min} \leq V_{b,m} \leq V_{b,max} \,, \quad \forall b \in B. \tag{4.2}$$

Constraints on the power flow of lines and transformers, l (L, set of branches):

$$\left(f_{l,m,t}^{(1,2),P}\right)^2 + \left(f_{l,m,t}^{(1,2),Q}\right)^2 = (f_l^+)^2 \;, \forall l \in L. \tag{4.3}$$

where $f_{l,m,t}^{(1,2),P}$ and $f_{l,m,t}^{(1,2),Q}$ are the active and reactive power injections at each end of the branch (denoted 1 and 2) and f_l^+ is the apparent power flow limit on the branch.

Kirchoff's current law describes the active and reactive power nodal balance, ($\forall\, l \in L$):

$$\sum_{l \in L} p_{b,m,t}^{L} + d_{b,m,t}^{P} = \sum_{g \in G} p_{g,m} + p_{x,m,t} \tag{4.4}$$

$$\sum_{l \in L} q_{b,m,t}^{L} + d_{b,m,t}^{Q} = \sum_{g \in G} q_{g,m} + q_{x,m,t}$$

(4.5)

Here $(p,q)^{L}_{b,m,t}$ are the total power injections onto branches b $(f^{1,(P,Q)}_{l,m,t} + f^{2,(P,Q)}_{l,m,t})$ and $d^{(P,Q)}_{b}$ is the peak active and reactive demands at the same bus. $p_{g,m}$ and $q_{g,m}$ are the active and reactive power from the distributed generation respectively, $p_{x,m,t}$ and $q_{x,m,t}$ are the active and reactive power injected/exported via the GSP. By incorporating active network management DNOs will have greater capability of optimizing the use of their assets through a combination of control. As the proposed technique is designed for use at the planning stage, several factors can be considered and "cherry-picked" to suit the designer. Two control methods selected for this representation of the planning framework included adaptive power factor control and energy curtailment. Control of the generator is dependent on the capabilities of the asset, power factor control can operate in a leading, unity or lagging power factor. The power angle of the generator, $\phi_{g,m}$, is considered a variable. Modern generators operate within a specific range of power factors ($\phi_{g,max}$ and $\phi_{g,min}$) and the following constraint applies:

$$\phi_{g,min} \leq \phi_{g,m} \leq \phi_{g,max} \tag{4.6}$$

Another method of control which can alleviate restrictions due to voltage and thermal limits being violated is energy curtailment. Formulation of active power curtailment is achieved by inserting a negative generation variable $\left(p^{curt}_{g,m}\right)$ at the same location as the DG unit. Regulatory changes are allowing an increase in the use of ANM, especially energy curtailment. A curtailment factor λ_{curt}, a percentage of the actual energy that might have been delivered by the DG, set at 1 for this research (therefore no limit set on level of curtailment possible). Developers may want to restrict the curtailment factor dependent on economic grounds. The energy curtailment constraint is as follows:

$$\sum_{m \in M} p^{curt}_{g,m}\, \tau_m \leq \lambda_{curt} \left[\sum_{m \in M} p_g \omega_m \tau_m \right], \;\; \forall g \in G \tag{4.7}$$

Here τ_m is the duration of period *m* within the year. The curtailment variables $p_{g,m}^{curt}$ is limited to the output of g at the corresponding period:

$$p_{g,m}^{curt} \leq \omega_m p_g, \quad \forall g \in G \tag{4.8}$$

The following constraints are added to comply with N-1 security measures. The set of contingencies k $(\in K)$ refer to the individual branches out of service. This means that the planned upgrades must comply with a set of voltage constraints and power flow constraints in all relevant configurations all year and periods in the year.

$$V_{b,min} \leq V_{b,m,t,k} \leq V_{b,max}\,, \quad \forall k \in K. \tag{4.9}$$

$$\left(f_{l,m,t,k}^{(1,2),P}\right)^2 + \left(f_{l,m,t,k}^{(1,2),Q}\right)^2 = \left(f_{l,k}^{+}\right)^2 \,, \forall k \in K. \tag{4.10}$$

4.4.2 Uncertainty considerations

Uncertainty is a major factor in planning the distribution network. Capturing what may or may not happen in the future is very difficult to model. In this research, the author has taken a simple approach which will be discussed in this sub-section. However, there are limitations by using this approach and these are reviewed in Chapter 7.

Within this research, the author decided to model uncertainty considering a range of scenarios for key parameters as this was the most time effective method. Uncertainty is critical in long term planning and various approaches exist, such as probabilistic, scenario and sensitivity which have a range of advantages and disadvantages and could have all been appropriate to use but the scenario option was chosen to illustrate. Factors such as maximum demand, maximum generation, the locational position of DG on the network, the annual demand growth, etc., are defined for each scenario. The program is then executed and the results documented for later comparison. The uncertainties deemed to result in the most significant impact on the planning of the distribution network are listed below and described in detail:

- Annual demand growth over the planning horizon;
- Demand variability;
- Generation location and quantity;
- Type of technology.

Annual Demand Growth

Demand growth has major significance in planning of the distribution network for the future. A large increase in demand will tend to result in more reinforcements compared to a scenario with only a small increase. Forecasting the annual increase is a difficult task due to the many variables involved. For example, it is increasingly dependent on the up-take of electric vehicles (EVs), the move towards electric heating, such as heat pumps (HPs) and the drive for consumers to utilise more energy efficient devices, for example LED lighting, all have a major impact on the level of demand in the future. Within this research, definition of four different scenarios of annual demand growth are used to simplify uncertainty for the planning model:

- Scenario 1 assumes there is no uptake of EVs or HPs alongside consumers moving towards a very energy efficient environment, thus a slight (2%) decrease in demand is visualised.
- Scenario 2 considers little up-take in EVs and HPs and a move towards energy efficiency, providing little in respect to annual demand increase, therefore, scenario two has a 1% annual increase in demand.
- Scenario 3 has a more general up-take of both EVs and HPs and a moderate to low level of consumer engagement in energy efficiency, this scenario has a 3% annual increase in demand.
- Scenario 4 realises the potential for EVs and HPs uptake alongside a lower than expected energy efficiency participation, thus having a 5% annual increase in demand.

Figure 4.1 displays the trajectory for each scenario and demonstrates a 181% difference in the final demand after 15 years between scenarios 1 and 4. This creates problems for DNOs, as over designing networks that never use the improved capacities will cost bill payers unnecessary charges. Equally, however, under-designing will create either unnecessary curtailment of demand or generation.

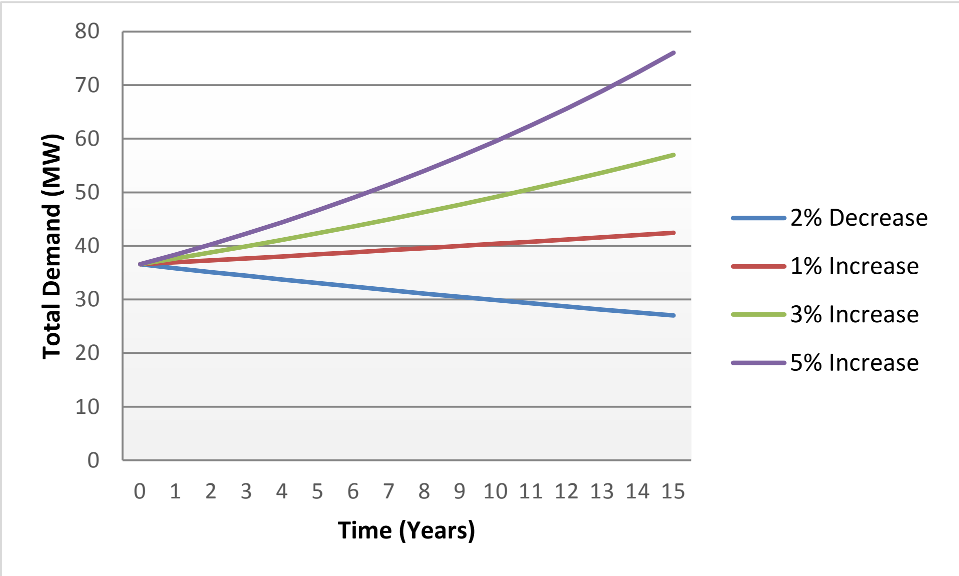

Figure 4-1 – Demand trajectory for various growth in peak demand over the planning horizon.

Demand Variability

Demand fluctuates on both a daily and seasonal basis dependent on user activity and the weather; it follows a typical profile as presented in Figure 4.2. Electricity generally cannot be stored, although energy storage is beginning to make a breakthrough, therefore generation must match the demand and any losses on the network in real-time. However, renewable generation is not dispatchable and is sometimes unable to meet this fluctuating demand. Therefore, at certain times of the day, especially during the night, renewable generation might be greater than the local demand. This scenario creates the situation where the power starts to flow in the reverse direction and export of electricity is then required onto the transmission network via the GSP. When this occurs, the increase in power flow can trigger reinforcements. The premise is that this can be controlled by active management schemes. Deferment of costly generation-triggered network infrastructure upgrades can therefore be realised, and as a result, additional DG could be consented.

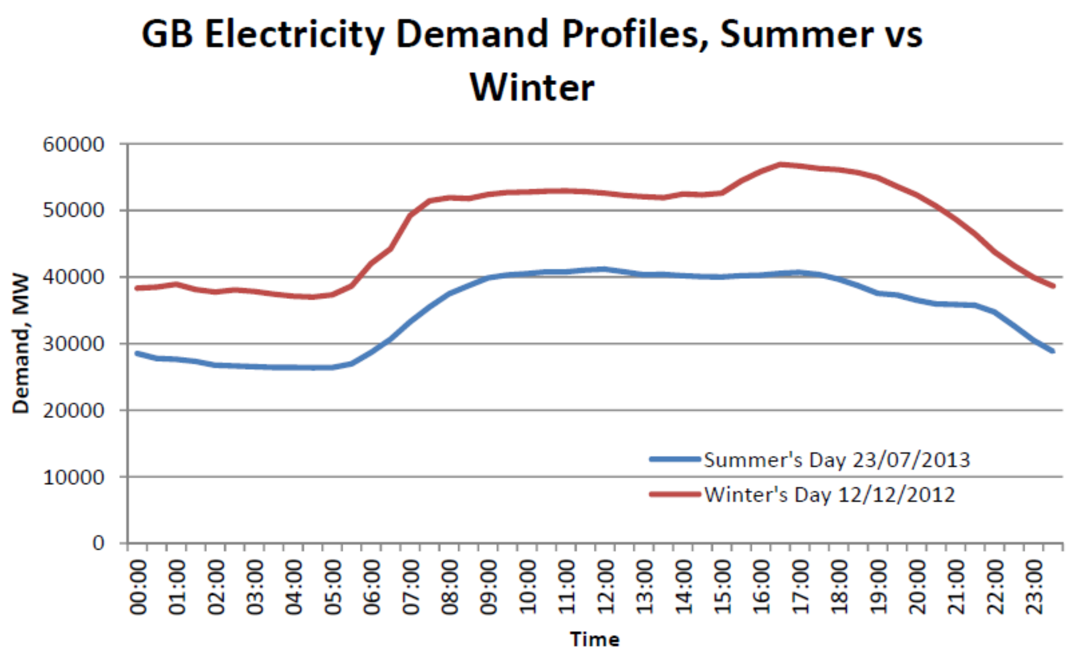

Figure 4-2 – Typical Daily Electricity Demand Profile for the UK [130].

To validate that the enhanced expansion planning method functions correctly, the maximum and minimum demands are applied. The maximum demand typically features on a cold winter day when consumers require the most levels of electricity for heating and lighting. The minimum demand usually occurs on a summer day, in the early hours of the morning, when heating and artificial lighting is not required.

Location and Quantity of Generation

Current regulations state that DNOs are not permitted to own or operate generation facilities. Therefore, private investors (developers) are required to build and operate generating stations to supply electricity. Developers use different financial models from that of DNOs and aim to build profitable stations. This may not always be in a location or at a level of generation beneficial to the network operator. For example, a majority of wind farms are likely to be located in remote parts of the country with ample wind resource but limited network infrastructure. The quantity of generation from wind farms also tends to be much higher than the local demand in the area and, therefore, require the electricity generated to be exported via the transmission network to other parts of the country. Wind farms generate electricity when there is sufficient wind resource and fluctuates between 0% and 100% of the rated output. The generation extremes of maximum and minimum generation have initially been utilised to validate the enhanced expansion planning method. Connecting DG as opposed to traditional reinforcements will tend to promote investment deferral. To investigate the relationship between locational impact, DG was connected at two buses within the test network.

Type of Generation

An important consideration for DNOs are the type of generation seeking connection; several factors concerning variability and capacity factor, are among the most important. Wind and solar resources vary on a daily basis and require a level of forecasting to determine when electricity will be generated. Forecasting may not always be precise. Therefore, demand may not always be able to be met by renewable generation. A CHP plant is non-intermittent and the quantity of generation available is relatively constant and known for the duration that the plant is running, although the generation might be restricted if the CHP plant is heat-led. However, in the initial research the type of generation was not a major factor and was not directly taken into account: only the maximum and minimum generation quantities were considered.

Capturing the uncertainty involved in planning of the distribution network into the enhanced expansion planning method requires consideration of a number of different scenarios. For example, the DG could be located at one of two buses. Four different demand and generation scenarios exist. Four separate annual demand growth are considered. Several quantities of DG are included within the model and this leads to numerous possibilities that require assessment. Figure 4.3 displays graphically the options possible. This indicates the options for the fit-and-forget DG, but an equal number of alternatives exist for controllable DG.

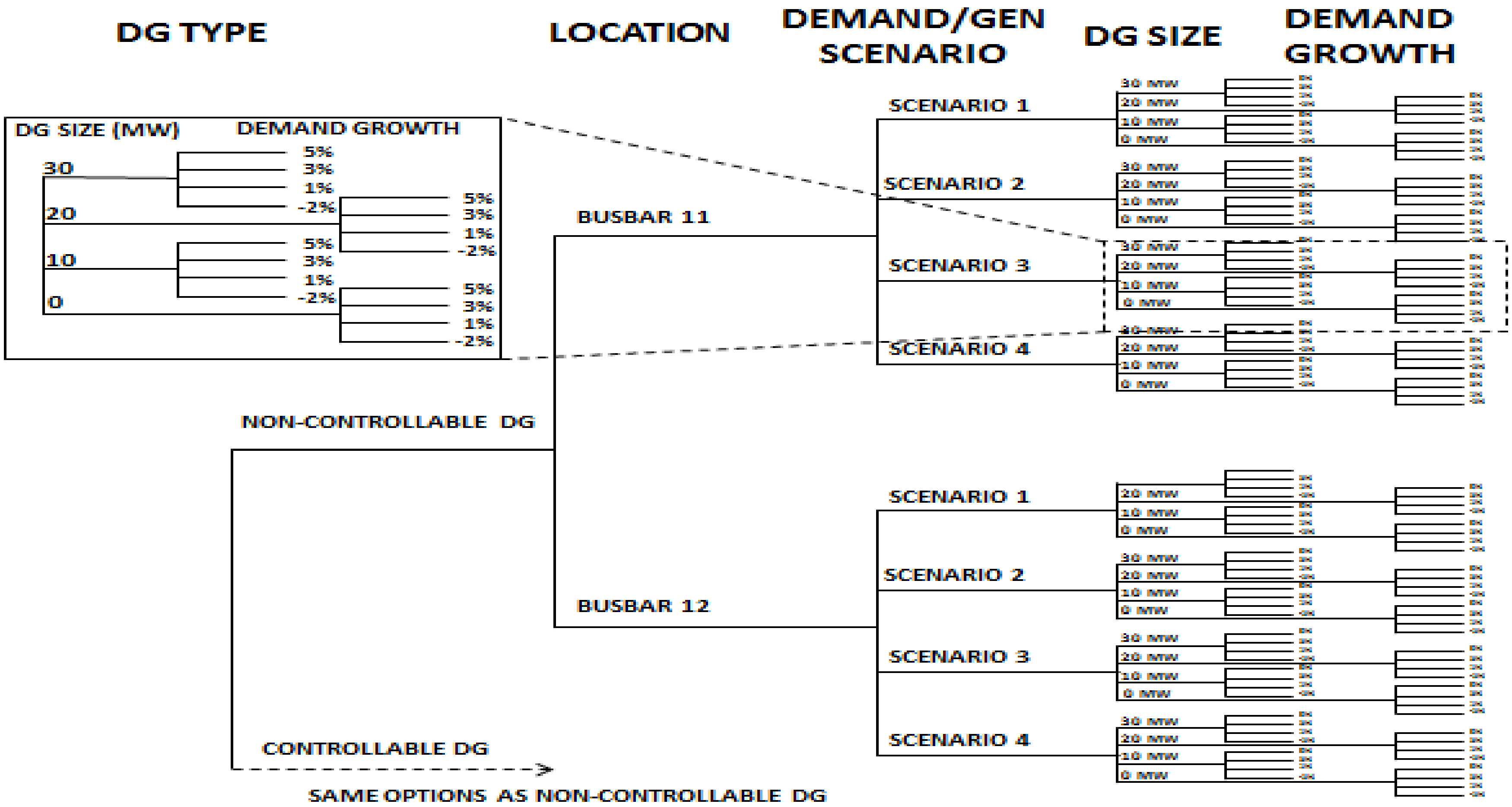

Figure 4-3 – The volume of possibilities for the Non-Controllable DG.

4.4.3 Generation and Demand Scenarios

As previous discussed, the demand and generation fluctuates between the maximum and minimum values. In the case of generation, this could mean anything from 0% to 100% and for demand, this typically ranges from approximately 40% (base load) to 100%. Therefore, four extreme scenarios exist: minimum generation/minimum demand; minimum generation/maximum demand; maximum generation/minimum demand; and finally maximum generation/maximum demand. These are illustrated in Table 4.1.

Table 4-1 - Generation and Demand Scenarios.

Scenario	Generation	Demand
A	Minimum	Minimum
B	Minimum	Maximum
C	Maximum	Minimum
D	Maximum	Maximum

If after analysing the four extremes scenarios, no network violations are experienced, these scenarios can be considered to have captured all possible situations that could arise from the various outputs of generation and demand profiles during any 24-hour period. The four extremes scenarios are employed in this research to provide an initial validation of the functional ability of the new expansion planning framework.

4.4.4 Successive Elimination Method

The SE algorithm was originally proposed by Brown *et al* [131] and further modified by Wang *et al* [132]. The original expansion planning method utilises a straightforward planning technique succeeding in acquiring the minimum required distribution network to operate safely and securely at the end of the planning horizon with an increased demand.

To start with, the SE method overbuilds the network by upgrading all the existing and potential overhead lines and transformers to contenders with greater capacity to handle the increase in demand at the end of the planning horizon. The algorithm starts to systematically reduce the capacity of each line and transformer, one at a time. If the network remains within the set constraints, i.e. no thermal or voltage violations exist, a “cost-effectiveness index” is calculated. The capacity is reinstated until all options have been assessed and finally the option with the least “cost-effective index” from the full pool has its capacity reduced permanently. This step is repeated until removal of any remaining contenders would result in violations. The SE method is often referred to as a “greedy heuristic” model as it examines all reinforcement options and chooses the best option. However, this makes it straightforward to understand and auditable. Figure 4.5 illustrates the flow chart for the SE method. Four steps are considered for the SE method and these include the following:

Step 1 – Calculate the demand at each bus at the end of the defined planning horizon considering the anticipated annual level of growth.

Step 2 – Overbuild the existing network by increasing the network capacity of each line and transformer to a larger capacity selected from standard ranges. Before starting the algorithm ensure no voltage or thermal violations exist on the overbuilt network.

Step 3 – Each expansion contender is removed one by one in turn and a feasibility check is carried out to confirm no constraints occur. If the feasibility check is unsuccessful, for example, voltage or thermal constraints occur, the cost-effectiveness for this option is set to very large number, such as 100,000. Otherwise, a cost-effectiveness is calculated using the following equation:

$$CE_a = \frac{\sum_{k \neq a} \left| P_{k\,new} - P_{k\,original} \right|}{Cost_a} \tag{4.11}$$

where CE_a is the cost-effectiveness measurement of option a in MW/\$, $P_{k\,original}$ is the total power flow (in MW) on branch k prior to option a being disconnected, $P_{k\ \mathrm{new}}$ is the total power flow on branch k once option a is disconnected, and $Cost_a$ is the cost of option a. An elimination list is created with all the cost-effectiveness answers stored. Option a is re-connected and step 3 is repeated until all expansion contenders have been assessed.

Step 4 – The elimination list is compared and the least cost effective contender from the full pool has its capacity reduced permanently. A security check is carried out to determine that the network would still operate in a secure and safe manner if any overhead line or transformer were removed due to a fault or for maintenance (N-1 security requirements). If this is successful the algorithm returns to step 3. However, if the elimination list only contains very large numbered cost-effectiveness measures (i.e. infeasible), then all remaining contenders are required to ensure the network is free from constraints. When this is the case, the final expansion plan has been established.

The overbuilt network considered by the SE method takes into account the upgrade of parallel or reinforcing of specific lines in a discrete manner. The consequence being that any future decision is influenced on the previous result, therefore, this method may not provide the optimal solution. However, the SE method will provide a solution that functions and the method is coherent and auditable.

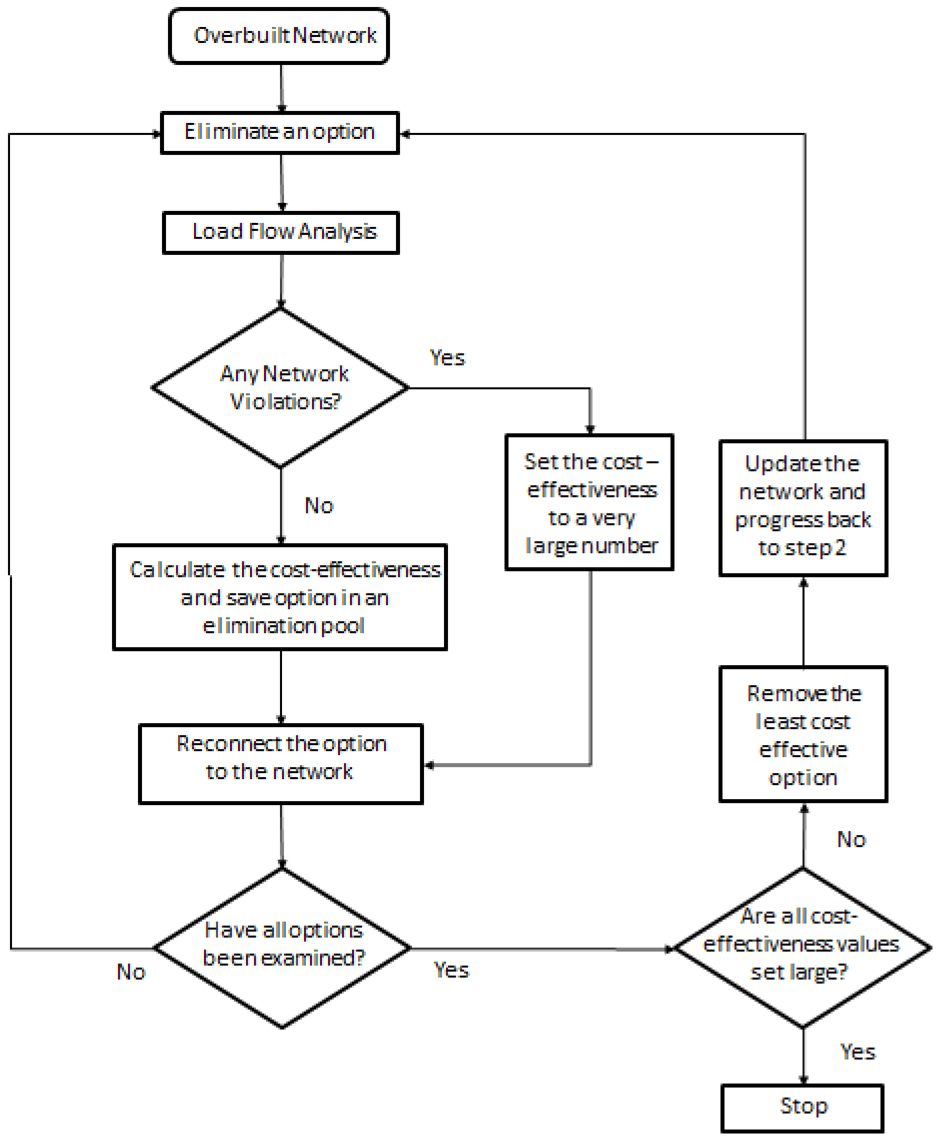

Figure 4-4 – Flow chart of the successive elimination method.

4.4.5 Multistage Planning Analysis

Wang *et al* combined the SE method with a modified multistage planning analysis. This altered the method from the original type by starting analysis at the end of the planning horizon as opposed to starting at the base year. Working backwards and decreasing the load gradually towards the base year allows for a more efficient process and is better suited to incorporating the SE method. The multistage planning analysis is an important stage, as it establishes in which year along the planning horizon that the critical network reinforcements are necessary to maintain safe and secure operation. Figure 4.5 illustrates the flow chart for the multistage planning analysis.

By commencing at the end of the planning horizon with the results established from the SE method, the modified multistage planning analysis requires the following steps:

> Step 1 – Add DG unit(s) at the base year and assume connection for the duration of the planning horizon. This step is disregarded when studying the scenario with no-DG connected.
>
> Step 2 – Utilising the previously explained cost-effectiveness tool, identify the contenders that are not essential that year, eliminating the least cost-effective option. Checks are performed to ensure safe and secure operation of the network under normal and N-1 security conditions. Once these checks are successful, the step is repeated until such time as removal of any remaining contenders would cause system violations.
>
> Step 3 – If the safety and security checks in step 2 are unsuccessful, the year is then brought backwards towards the base year and the demand is reduced accordingly. Step 2 is undertaken once more, until the base year is reached. At this point the analysis is complete.

Subsequently connecting DG to the model and re-running the multistage planning analysis, makes it possible to calculate the investment deferral achieved by considering DG as an alternative to traditional reinforcements.

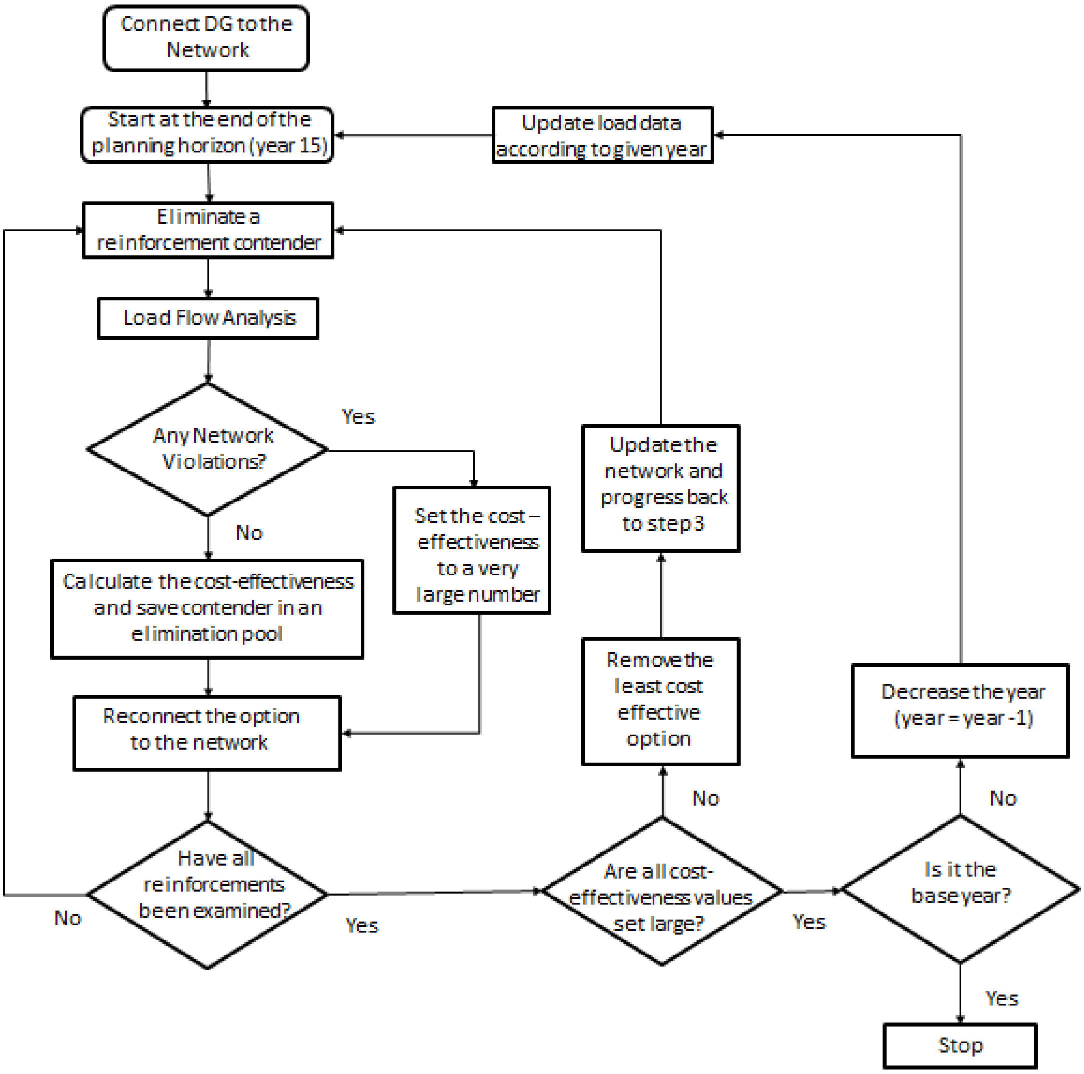

Figure 4-5 – Flow chart for the multistage planning analysis.

In this research, the multistage planning analysis is modified to enhance the possible level of investment deferral. It is clearly observed that incorporating DG as an alternative to traditional reinforcement has benefits [13]. Further advantages could be realised by incorporating active management control techniques into the planning model to represent the actual operational practices currently or potentially used. This could be achieved by simulating actions of the DNO in issuing control instructions to the DG unit when network violations occur. In this particular implementation the local controller does the same job. If the additional generation creates a voltage rise issue, a control instruction to the DG adjusts its active and/or reactive power according to calculations carried out by the sensitivity analysis. This analysis manipulates data recorded from the simulated network model, which provides voltage and current values at the DG's point of connection. Calculations are carried out to determine the required change in active and/or reactive power output of the DG unit to maintain the network's voltage and power flow within the limits. To incorporate this, step 3 of the SE method is revised to include controllable DG:

> Step 3 - If the safety and security checks in step 2 are unsuccessful, instead of initially decreasing the year closer to the base year, adaptive control is explored. Voltage and thermal management is utilised to identify if actively controlled DG could be embraced as an alternative to traditional reinforcements. After more security and feasibility checks, if violations continue to occur, the demand is reduced to correspond with the reduction in year closer to the base year. Step 2 is undertaken once more, until the base year is reached, at this point the analysis is complete.

Figure 4.6 illustrates the modified flow chart for the multistage active network planning analysis. The following sub-section describes in detail the mechanism behind the adaptive control "plug-in" introduced to the multistage planning analysis.

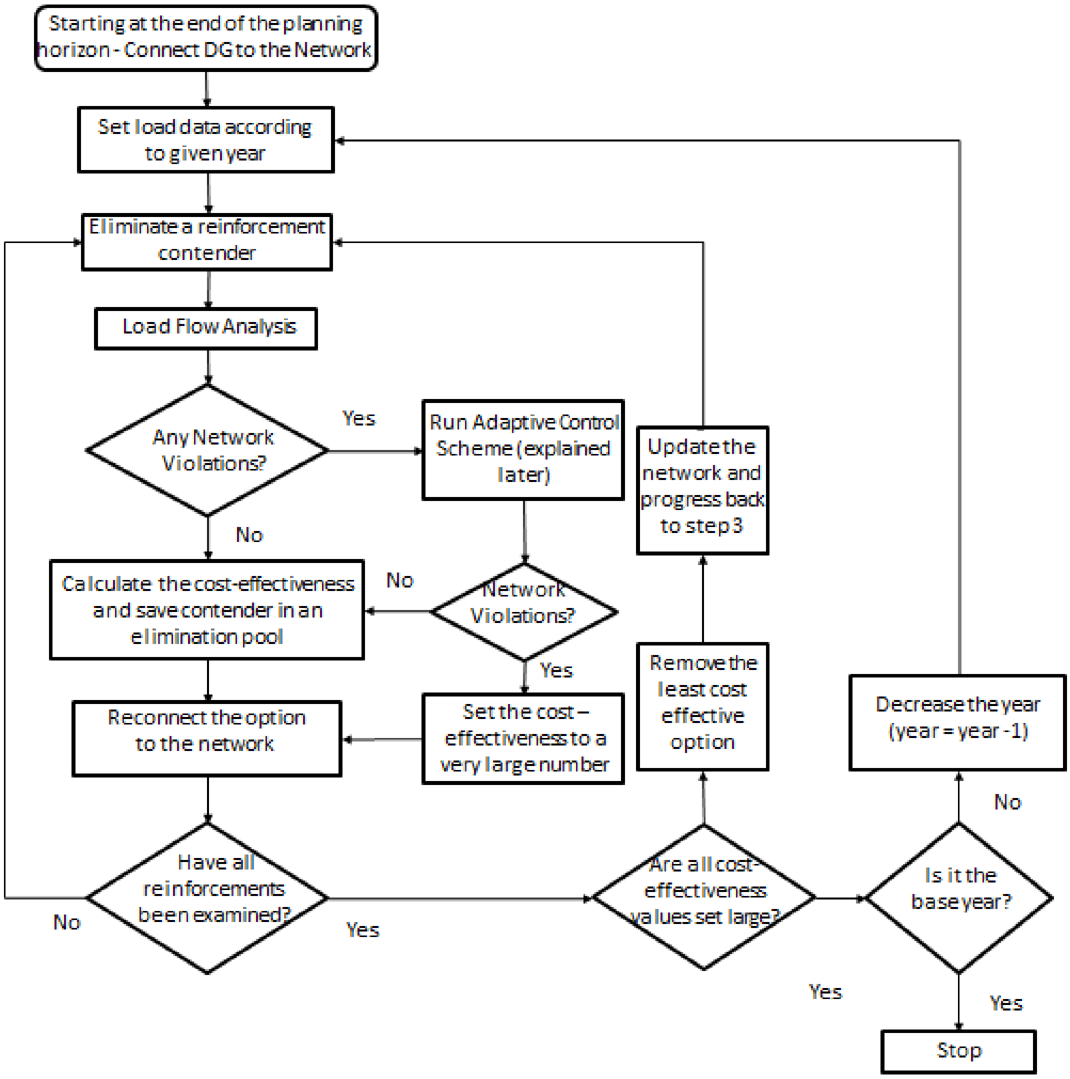

Figure 4-6 – Flow chart for the enhanced multistage planning analysis incorporating controllable DG.

4.4.6 Adaptive Control for Voltage and Thermal Management

Historically, power factor had to remain at unity to grant maximum power output but with developments in technology, the latest wind turbines are capable of operating at maximum power output whilst varying reactive power. Modern wind turbines are capable of operating within a range of power factors, typically ranging from 0.95 inductive to 0.95 capacitive (absorbing/producing reactive power respectively). DNOs have an opportunity to exploit this capability to maintain the voltage profile of the network, especially at the point of connection and the surrounding area. Power factor control reduces the likelihood of interference with OLTC transformers and/or line drop compensators, the traditional approaches for voltage regulation.

The voltage management strategy incorporates the idea of the voltage control scheme developed by Sansawatt employing active and/or reactive power control capabilities of the DG unit. Initially, reactive power control is exhausted before active power management is implemented to allow maximum power export to be achieved. Voltage constraints are managed by applying the voltage limit as the threshold value, which determines when control actions are required. Within the simulation, voltage levels are measured at the point of connection, and corrective actions are taken when these values exceed the threshold limit. Two methods are applied to maintain the voltage profile of the network within the statutory limits: (i) reactive power control using sensitivity analysis to identify the reactive power set point; (ii) active power curtailment by providing an active power set point. Once the corrective action has been performed, further feasibility and security checks are executed to confirm that the voltage management scheme has mitigated the network constraint.

Voltage Management - Reactive Power Control

Subject to the type and size of the DG unit and network operation parameters, utilisation of a DG's ability to operate at various power factors can provide reactive power support according to:

$$Q_{Inductive}, Q_{Capactive} = \frac{P}{power\ factor} \times \sqrt{1 - \ power\ factor^2} \qquad (4\text{-}12)$$

where $Q_{Inductive}$ ($Q_{Capactive}$) is the DGs inductive(capacitive) reactive power, P is the DG power output, and *power factor* is the DG maximum power factor. Using equation (4-8), approximately 0.33 MVar of inductive/capacitive reactive power would be available from a generator of 1MW with a typical 0.95 power factor capability.

Figure 4.7 illustrates a functional chart for the reactive power management scheme. The symbols PF_{min}, PF_{new} and PF_{max} represent the minimum, new (target) and maximum power factor values, respectively. Calculated from the former values and the active power, are the minimum (Q_{min}), new (Q_{new}) and maximum (Q_{max}) reactive power values. Within the network model, the voltage at the DG's point of connection is compared against the statutory limits. If the voltage is within the threshold, then no corrective action is required and a constant power factor, most likely to remain at unity, is maintained. On the other hand, if the voltage violates the statutory limits, a voltage control method is executed to return voltage within the limits by providing reactive power compensation. In this scheme, a set point is issued and the generator will adjust the power factor to become more inductive or capacitive depending on whether the violation is voltage rise or drop, respectively.

A sensitivity analysis approach is used to compute a new power factor set point. In principle these factors would be those within the Jacobian matrix in the power flow. In practice these are calculated directly using successive runs of power flow engine. Firstly, the reactive power control sensitivity is determined by the voltage deviation (∂V) to a nominal 1-MVar (∂Q) decrease of the generator. This solution is applied to the limit and "measured" voltages to calculate the required difference (ΔQ) of reactive power to maintain the voltage within the limits as in the following:

$$\Delta Q = \frac{V_{measured} - V_{limit}}{\frac{\partial V}{\partial Q}} \tag{4.13}$$

where ΔQ is the difference in reactive power required to maintain the voltage within the statutory limits, $V_{measured}$ is the measured or present voltage, V_{limit} is the voltage limit, ∂V is the voltage deviation and ∂Q is the reactive power deviation.

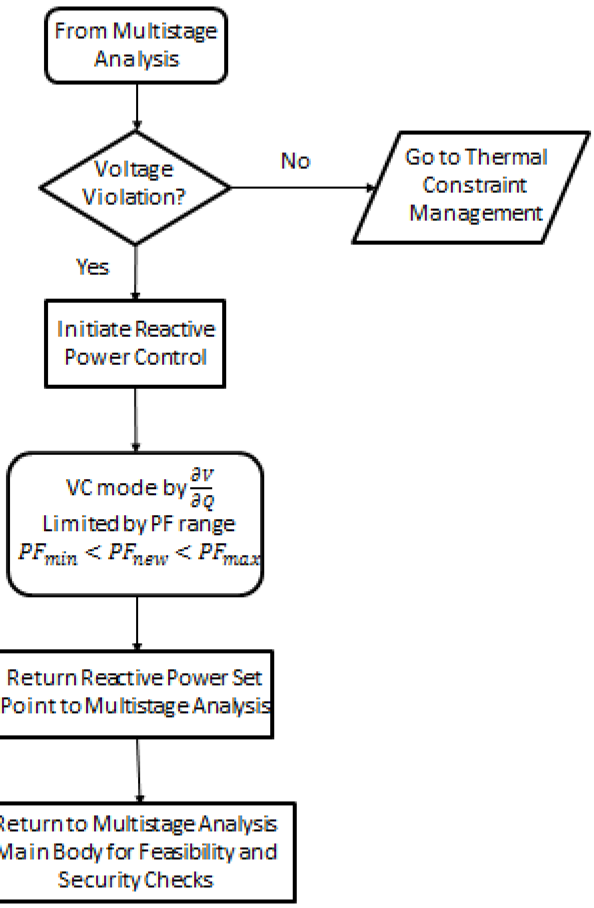

Figure 4-7 – Functional chart for reactive power management.

Voltage Management - Active Power Control

Reactive power control is restricted to the capability of the DG unit. Once this capability is exceeded and the voltage remains beyond the limit, active power curtailment is essential to adjust the voltage profile. A set point is issued to the generator to trim its power output. This typically occurs during periods of low demand but high generation. Figure 4.8 shows a functional chart for the voltage management active power curtailment model. Similar to the reactive power control, sensitivity analysis is utilised to calculate the level of active power to curtail. A calculation of voltage deviation (∂V) from reducing the generator's output by 1-MW (∂P) is carried out. This calculation uses the measured and limit voltages to calculate the total active power required to be trimmed to maintain the voltage within the statutory limit according to:

$$\Delta P = \frac{V_{measured} - V_{limit}}{\frac{\partial V}{\partial P}} \tag{4.14}$$

where ΔP is the difference in active power required to maintain the voltage within the statutory limits, $V_{measured}$ is the measured voltage, V_{limit} is the voltage limit, ∂V is the voltage deviation and ∂P is the active power deviation.

The generator capabilities, being the reactive power range and ramp rates, will limit the actual active and reactive power achievable by the DG unit. This requirement would be essential at the time of procurement to ensure it meets with the network operator's conditions. Within this research, it is assumed that once the curtailment is achieved that the voltage would remain within the thresholds, however, further feasibility and security checks are completed to confirm this. Once these checks have verified that voltage(s) could be safely brought back within limits, the algorithm then switches back to the main body of the multistage analysis, which calculates the cost-effectiveness of the contender and saves this quantity within the cost-effectiveness pool. If curtailment is not able to maintain voltage levels, the cost-effectiveness value is set very high, similar to the security checks returning false in the main multistage algorithm.

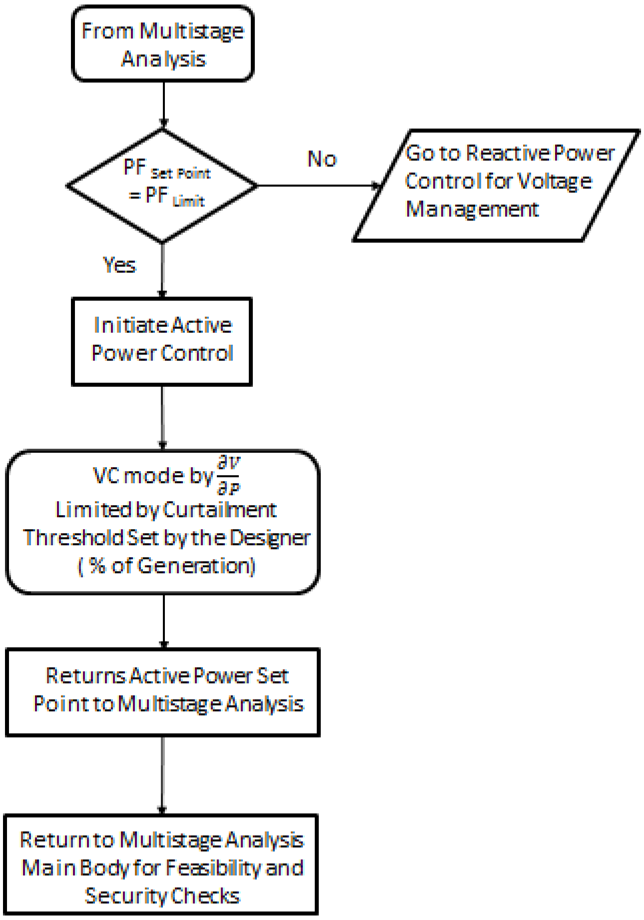

Figure 4-8 – Functional chart for voltage control active power management.

Thermal Management - Active Power Control

Similar to the active power control for voltage management issues, the thermal management control is concerned with reducing the level of active power to ensure that the maximum line capacities are not exceeded. Figure 4.9 shows a functional chart for the thermal management active power curtailment model. The level of power to be trimmed in order to maintain loading within the line capacity is estimated using the sensitivity approach. Line loading deviation (∂S) is calculated by decreasing the output of the generator by 1-MW. The scheme monitors the power flowing through the lines against the maximum capacity. Should the measured power exceed the line loading capacity, constraining actions are employed. An estimation of the required active power curtailment required to maintain line loading levels within the physical limits utilises the line loading deviation and the measured and limit power flows according to:

$$\Delta P = \frac{S_{measured} - S_{limit}}{\frac{\partial S}{\partial P}} \tag{4.15}$$

where ΔP is the difference in active power required to maintain the power flow within the physical limits of the asset, $S_{measured}$ is the measured power flow, S_{limit} is the power flow limit, ∂S is the line loading deviation and ∂P is the active power deviation.

Curtailment limits can be set within the planning strategy to regulate the size of active power curtailment possible. There becomes a tipping point wherein, increased levels of curtailment reduces the level of revenue from exporting electricity to a level that effectively makes the project financial unviable. Similarly, if levels of curtailment are high, this generally signals that network reinforcements are essential especially if any further DG developments emerge.

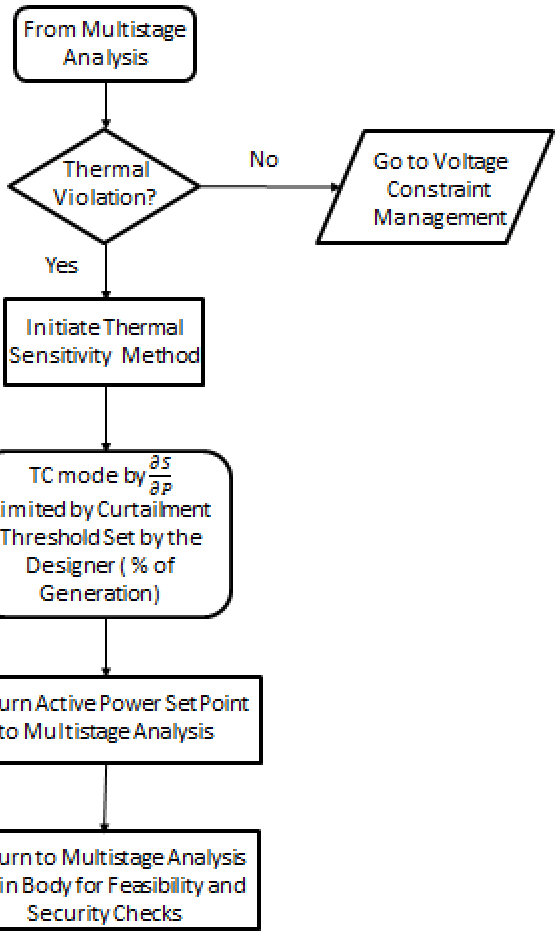

Figure 4-9 – Functional chart for thermal control active power management.

4.4.6 Quantifying Investment Deferral

To quantify investment deferral, the cost for traditional reinforcements along the planning horizon is required. The multistage analysis is executed with no DG output to determine the instances in time along the planning horizon for when demand-triggered reinforcements are essential to maintain safe and secure operation. The total discounted cost of the upgrades is calculated using the present value (PV) method for the established expansion plan by:

$$PV = \sum_{t=1}^{h} \sum_{i=1}^{n} \frac{C_{i,t}}{(1+\rho)^t} \tag{4.16}$$

where h is the length of the planning horizon in years, n is the number of reinforcements required for year t, c_i is the cost of asset i required in year t, and ρ is the discount rate.

To ascertain the level of investment deferral created by connecting DG as an alternative to installing traditional network reinforcements, requires calculation of the difference in PV between the plan without DG and that with DG, as follows:

$$Investment\ Deferral = PV_{no\ DG} - PV_{DG} \tag{4.17}$$

4.5 Case Study

In this section, the additional investment deferral created by incorporating adaptive control into the expansion planning method is validated on a small generic distribution network. Four separate annual demand growth rates and two independent DG locations are considered. To capture the numerous options outlined previously, 32 scenarios, as illustrated in Table 4.2 have been created to examine several possibilities. Within the enhanced expansion planning method the quantity of connected DG is increased from an initial 0MW to 60MW in 5MW increments.

4.5.1 Network Characteristics and Assumptions

The methodology is applied to a modified rural 12-Bus 33kV distribution network developed by the UK Generic Distribution System (UK GDS) [133], as shown in Figure 4.10. The network parameters are provided in Appendix A. Power is supplied to the radial system from a single GSP and distributes power to 10 loads scattered throughout the network at the 33kV voltage level. Total maximum load in the base year is 36.5MW, and ranges from 27MW to 76MW over the four different annual load growth percentages under consideration across a 15-year planning horizon.

Reinforcements postponed beyond the end of the planning horizon are assumed to be carried out in year 15 as opposed to complete avoidance. This may seem a little conservative and underestimates the actual deferment possible. However, DG only delays the requirement for reinforcements and will not always negate upgrades, as increase in demand beyond the end of planning horizon may eventually trigger network infrastructure reinforcements.

DG is initially connected to bus 11, and subsequently bus 12, to allow for a comparison of locational impact. Several scenarios are computed. Firstly, the simulation is executed with no control capabilities attached to the DG, which determines the base investment deferral for comparison. Next, adaptive control capability is inserted into the model to demonstrate the additional investment deferral that can be achieved.

System security applied within the modified 12-Bus network comprises the following rules. Firstly, the adopted N-1 security constraint affects lines and transformers that run in parallel, therefore, the secondary line/transformer will have spare capacity to transfer 100% of the required power in the event that a fault occurs. Secondly, single lines and transformers that connect to loads which have a second supply from elsewhere are included within the N-1 security constraint. For example, if line 2-3 is disconnected, energy is supplied to bus 3 via lines 2-4 and then 3-4.

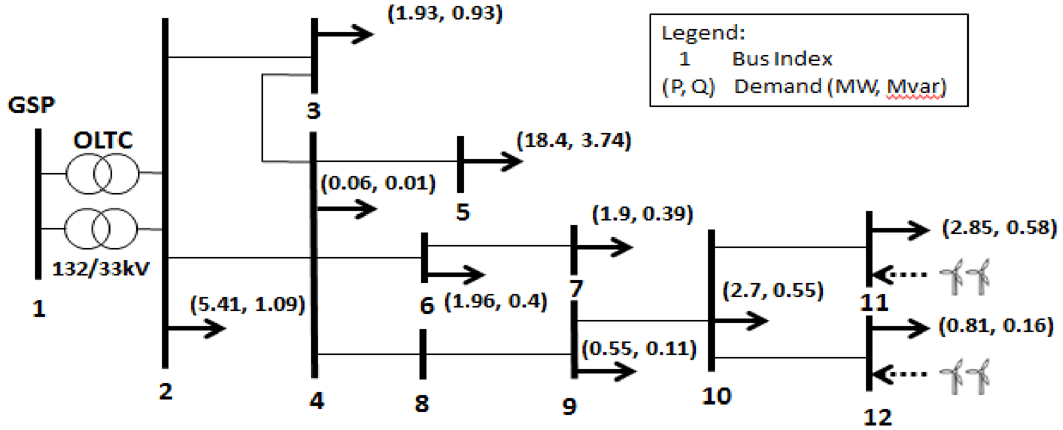

Figure 4-10 – Modified 12-Bus 33kV rural distribution network (UK GDS [133]).

Table 4-2 – 32 scenarios examined.

Scenario	Controllable DG	Percentage annual demand increase	Percentage maximum demand	Connected at bus
1	No	5%	100%	11
2	No	5%	40%	11
3	No	5%	100%	12
4	No	5%	40%	12
5	No	3%	100%	11
6	No	3%	40%	11
7	No	3%	100%	12
8	No	3%	40%	12
9	No	1%	100%	11
10	No	1%	40%	11
11	No	1%	100%	12
12	No	1%	40%	12
13	No	-2%	100%	11
14	No	-2%	40%	11
15	No	-2%	100%	12
16	No	-2%	40%	12
17	Yes	5%	100%	11
18	Yes	5%	40%	11
19	Yes	5%	100%	12
20	Yes	5%	40%	12
21	Yes	3%	100%	11
22	Yes	3%	40%	11
23	Yes	3%	100%	12
24	Yes	3%	40%	12
25	Yes	1%	100%	11
26	Yes	1%	40%	11
27	Yes	1%	100%	12
28	Yes	1%	40%	12
29	Yes	-2%	100%	11
30	Yes	-2%	40%	11
31	Yes	-2%	100%	12
32	Yes	-2%	40%	12

4.5.2 Demand Led Expansion Plan

The first step within the enhanced expansion planning method is to establish the minimum required reinforcement works to maintain a safe and secure network with the proposed increase in demand at the end of the planning horizon. This is completed by running the SE method. The infrastructure upgrades are therefore dependent on the level of annual demand growth. Due to the uncertainty associated when forecasting ahead, several demand increase scenarios were employed. Table 4.2 demonstrates four different annual demand growth rates applied to the model to consider this uncertainty.

The results from running the SE method are presented in Table 4.3 and clearly show that the higher the expected annual demand growth, the greater the level of reinforcements are required. With an annual increase of 5%, reinforcements are required on six overhead lines. Two are upgrades of the existing lines, both increasing capacity and four were the addition of a parallel line, adding capacity to the existing circuit. Reducing the annual demand growth to 3%, reduced the level of reinforcements, only two lines required upgrading to increase capacity. Upon further reduction to 1% annual demand growth presented a further reduction in the level of reinforcements: two new parallel lines are required to increase the circuit's capacity. Finally, with a 2% decrease in annual demand growth, as expected, no new demand-driven assets were required. However, any sufficient increase in generation would therefore trigger generation-driven reinforcements to be able to accommodate the increased power flow.

Table 4-3 – Reinforcements required for various demand increases.

	Reinforcements		
Annual demand increase (%)	Upgrades	Parallel	Total
-2	0	0	0
1	0	2	2
3	2	0	2
5	2	4	6

Table 4.4 indicates the costs associated with the reinforcement options for overbuilding the distribution network. These $/MWh costs are indicative and are obtained from paper [134]. Using these costs opposed to current figures allows a straightforward comparison to be made against the work carried out previously by Wang [132].

Table 4-4 – Cost of reinforcement options [134].

Overhead Line		
Voltage (kV)	Capacity (MVA)	Cost (US$k)
132	100	180
132	120	200
33	60	120
33	80	150

Transformer		
Voltage (kV)	Capacity (MVA)	Cost (US$k)
132/33	80	1500
132/33	100	1700
33/11	23	350
33/11	30	420

Once the SE method has been performed and the network model is updated to reflect the results, the multistage analysis is executed without DG connected to the network. This establishes at which time along the planning horizon the reinforcements are required. Table 4.5 presents the year that each reinforcement is required and the PV cost for the 5% demand growth case.

Table 4-5 – Scheduling of new branches required along the 15 year planning with no DG connected and 5% annual demand growth.

Branch	Asset	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
2-3	OHL	Upgrade	2 x 60	120	12.5	9	1775.70
2-4	OHL	Parallel	1 x 35	96	18.5	1	1675.47
3-4	OHL	Parallel	1 x 35	96	8.8	8	530.04
4-5	OHL	Upgrade	1 x 60	120	2.1	12	125.24
8-9	OHL	Parallel	1 x 35	96	10.1	11	510.77
9-10	OHL	Parallel	1 x 35	96	22.3	12	1063.91
						Total	5681.13

The total planning cost in present value for reinforcements required for 5% annual demand growth comes to US$5.68m. One reinforcement is essential immediately with the others are required over a four-year period between year four and year eight of the planning horizon.

Table 4.6 introduces the cost associated with an annual demand growth of 3%. Two overhead lines (OHL) require reinforcement to enable the network to meet the increased demand at the end of the planning horizon. The SE method estimates the least cost option for reinforcements and consists of new parallel upgrades of branches 2-3 and 3-4. The multistage analysis goes on to evaluate that branch 2-3 is required in year 1 and branch 3-4 is essential in year 4.

Table 4-6 – Scheduling of new branches required along the 15 year planning with no DG connected and 3% annual demand growth.

Branch	Asset	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
2-3	OHL	Upgrade	2 x 60	120	12.5	1	2830.19
3-4	OHL	Upgrade	2 x 60	120	8.8	4	1672.90
						Total	4503.09

In Table 4.7, the scheduling of new branches for an annual demand growth of 1% is demonstrated. It shows that two OHL require reinforcements, the first coming in year 5 at branch 2-4, consisting of a second parallel line. The second reinforcement comes at the end of the planning horizon in year 15, a second parallel line at branch 3-4.

Table 4-7 – Scheduling of new branches required along the 15 year planning with no DG connected and 1% annual demand growth.

Branch	Asset	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
2-4	OHL	Parallel	1 x 35	96	18.5	5	1327.13
3-4	OHL	Parallel	1 x 35	96	8.8	15	352.51
						Total	1679.64

The case with a decrease in annual demand at a reduction rate of 2%, as expected requires no reinforcements. The existing distribution network adequately maintains safe and secure operation.

4.5.3 Expansion plan considering DG

Within the scope of this research, inserting DG onto the existing distribution network is considered an alternative approach to reinforcement. Generally speaking, DG should mitigate a proportion of demand growth and therefore defer reinforcements.

For the 5% demand growth case Table 4.8 displays the scheduling of reinforcements required over the planning horizon for a variety of firm DG capacities. The resulting fall in investment costs equates to a 18.9% investment deferral with the addition of 5MW at bus 11. This increases to a maximum of 33.5% of investment deferral with 40MW of connected DG. All branches requiring reinforcements are deferred by 1 to 10 years, dependent on the level of DG inserted. Once DG exceeds 42MW further investment is required to provide generation-driven reinforcements. Figures 4.11 and 4.12 shows that by increasing the level of connected DG, extra investment deferral is possible. The level of investment deferral closely matches each other, however, bus 11 can accommodate approximately 5MW more than bus 12 due to the higher levels of demand experienced. Any further generation requires reinforcements to allow transfer of energy away from the bus.

Table 4-8 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 5% demand growth.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4									10-11	10-11	10-11	10-11
4		2-4											
6			2-4										
8	3-4			2-4								`	
9	2-3												
10					2-4								
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	3776.0	6056.0	6056.0	6056.0	6056.0

Table 4-9 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 5% demand growth.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4								10-12	10-12	9-10 10-12	8-9 9-10 10-12	8-9 9-10 10-12 *
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9	2-3 2-4 3-4	2-3 2-4 3-4
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	7712.0	7712.0	9472.9	9983.1	13696.3

* Branch 10-12 requires an additional upgrade consisting of a second new overhead line

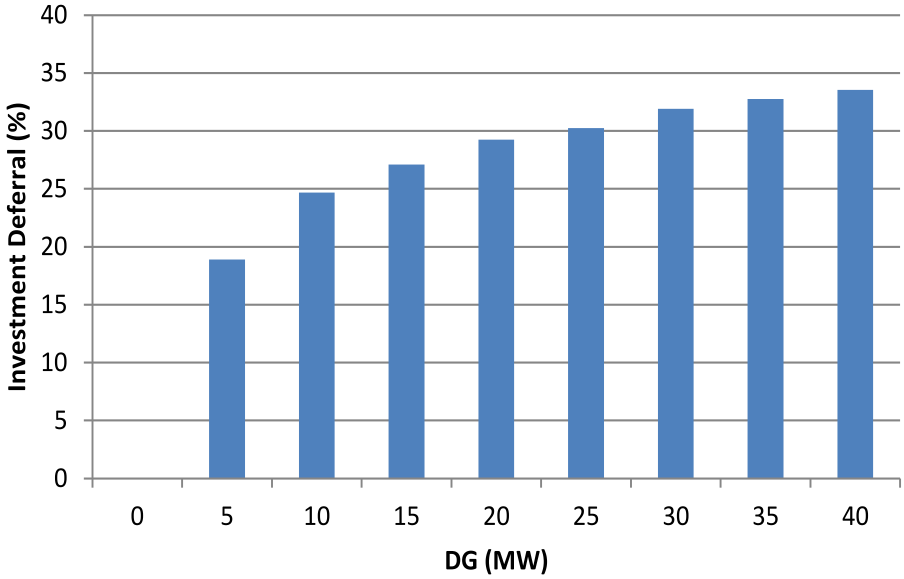

Figure 4-11 – Investment deferral benefits with DG located at bus 11 with various capacities, for 5% demand growth case.

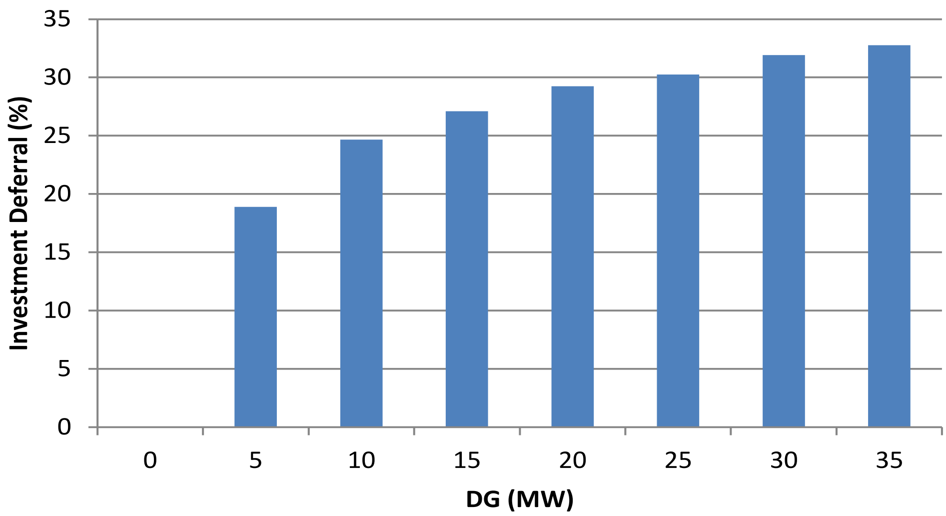

Figure 4-12 – Investment deferral benefits with DG located at bus 12 with various capacities, for 5% demand growth case.

Tables 4.10 and 4.11 display the scheduling of new branches for 3% annual demand growth at buses 11 and 12 respectively. These results shows that DG can be utilised as an alternative to traditional reinforcements, but limits of maximum DG output are dependent on individual network capacity.

Table 4-10 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 3% demand growth.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-3									10-11	10-11	10-11	10-11
4	3-4												
6		2-3											
8		3-4											
10			2-3										
12			3-4										
13				2-3									
14					2-3								
15				3-4	3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4
Total Investment (10^3 US$)	4503.1	3440.0	2724.8	2287.8	2133.1	2133.1	2133.1	2133.1	2133.1	4413.1	4413.1	4413.1	4413.1

Table 4-11 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 3% demand growth.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-3								10-12 *	10-12	9-10 10-12	8-9 9-10 10-12	8-9 9-10 10-12
4	3-4												
6		2-3											
8		3-4											
10			2-3										
12			3-4										
13				2-3									
14					2-3								
15				3-4	3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4
Total Investment (10^3 US$)	4503.1	3440.0	2724.8	2287.8	2207.2	2133.1	2133.1	2133.1	5281.9	6069.1	8593.6	9736.9	9736.9

* parallel reinforcement, all others DG capacities require a full upgrade of the overhead line.

Tables 4.12 and 4.13 show the scheduling of new branches required when considering a 1% annual demand growth. Minimum reinforcements are required for the increase in demand over the 15 year planning period. However, generation-driven reinforcements are essential for smaller amounts of DG as the absence in additional demand prevents the same level of DG to be connected as in the previous two cases of 5% and 3% growth.

Reducing the expected demand by 2% every year does not require any demand-driven reinforcements as shown in Tables 4.14 and 4.15, however, the reduced capacity experienced triggers generation-driven reinforcements to be required for lower capacities of DG than the cases with annual demand growth.

Table 4-12 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 1% demand growth.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1									10-11	10-11	10-11	10-11	10-11
5	2-4												
15	3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4
Total Investment (10^3 US$)	1679.6	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	3373.6	3373.6	3373.6	3373.6	3373.6

Table 4-13 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 1% demand growth.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1								10-12	10-12	9-10 10-12	9-10 10-12	9-10 10-12	8-9 9-10 10-12
5	2-4												
15	3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4
Total Investment (10^3 US$)	1679.6	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	5029.6	5029.6	7554.1	7554.1	7554.1	8697.5

Table 4-14 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 2% demand reduction.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1								10-11	10-11	9-10 10-11	9-10 10-11	9-10 10-11	8-9 9-10 10-11
Total Investment (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2280.0	2280.0	4299.6	4299.6	4299.6	5214.3

Table 4-15 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 2% demand reduction.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1								10-12	10-12	9-10 10-12	9-10 10-12	8-9 9-10 10-12	8-9 9-10 10-12
Total Investment (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3936.0	3936.0	5673.3	5673.3	6816.7	6816.7

4.5.4 Expansion plan considering controllable DG

In Section 4.6.3 it was demonstrated that DG could defer investment by delaying the need for reinforcements. After integrating adaptive control by the means of sensitivity analysis and permitting the control of active and/or reactive power to facilitate the management of thermal and voltage constraints, additional investment deferral can be realistically compared to the connection of firm DG alone. Tables 4.16 and 4.17 present the new schedule required during the planning horizon for various quantities of controllable DG at bus 11 and 12 respectively. The adaptive control can defer generation-driven investment, however, the drawback is that revenue will be lost due to the curtailment of active power to prevent the network from experiencing violations. The cost of lost revenue specified in Tables 4.16 – 4.23 assume a cost of \$100/MWh for electricity. The 5% demand growth case uncovers a 12.3% increase in investment deferral for connection of 45MW controllable DG at bus 11 compared to the results obtained from the firm connection. However, an 8.8% of curtailment is required to maintain system operation and while employing the worst-case scenario, this results in 34,690 MWh of energy lost throughout the year. This is not a true estimate, as the capacity factor of the generation is not considered within the calculations. In Chapter 5, this will be addressed by considering a time series method.

It should be noted that the value given here relate to the curtailment in the final year of the analysis, rather than a year-by-year or lifetime total. This was a limitation in the implementation as the analysis works backwards until the point at which an upgrade is required, it does not automatically analyse every year. As such, it was not possible to fully appraise the timing of the curtailment in each year (essential for discounted cash flow analysis) for direct comparison with the investment cost. This information could be produced by running a simulation for each yearly configuration and retaining the relevant data; this is an area for further work. Of further note, the monetary value for curtailment is not discounted to account for it being in year 15 which would reduce the present value to just under half. The values, however, offer a useful indicator of the relative size of the curtailment required in each instance.

Table 4-16 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 5% demand growth and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4												
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	3776.0	3776.0	3776.0	3776.0	3776.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34689.6	91542.0	158512.2	236520.0
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.8	20.9	32.9	45.0
Cost of Lost Revenue (10^3US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3468.9	9154.2	15851.2	23652.0

Table 4-17 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 5% demand growth and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4												
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	3776.0	3776.0	3776.0	3776.0	3776.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18816.5	73084.7	138889.8	216280.0	305163.4
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	18.5	31.7	44.9	58.1
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1881.7	7308.5	13890.0	21628.0	30516.3

Tables 4.18 and 4.19 display the scheduling of new branches for the 3% annual demand growth at buses 11 and 12 respectively. These results also iterate that additional controllable DG can be connected with some curtailment. The quantity of curtailment is increased due to the lower demand reducing the available network capacity. Tables 4.20 and 4.21 represent the scheduling of reinforcements for an annual demand growth of 1%. The level of curtailment increases compared with both the 3% and 5% growth cases. This is due to another reduction in available network capacity and therefore limits the output of DG possible before reinforcements are required.

Tables 4.22 and 4.23 represents the curtailment required for controllable DG while examining the case with a 2% reduction in demand. A high level of curtailment is experienced for all quantities of connection compared with the cases with positive annual demand growth.

Figure 4.13 displays a graphical representation of the increase in curtailment required to connect a 50MW generator at bus 11. It can be seen that as the annual demand growth is reduced the level of curtailment increases. A 21% curtailment rate is experienced with a 5% annual demand growth and this is compared to 49% rate observed when a 2% demand reduction is examined.

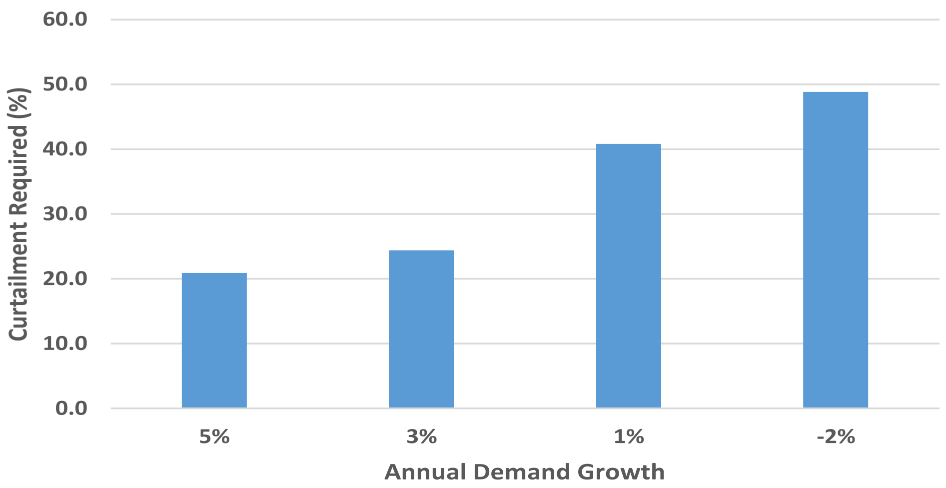

Figure 4-13 – Indicative curtailment required with 50MW of DG connected at bus 11.

Table 4-18 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 3% demand growth and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-3												
4	3-4												
6		2-3											
8		3-4											
10			2-3										
12			3-4										
13				2-3									
14					2-3								
15				3-4	3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4
Total Investment (10^3 US$)	4503.1	3440.0	2724.8	2287.8	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46909.8	106872.0	177302.4	259120.8
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.9	24.4	36.8	49.3
Cost of Lost Revenue (10^3US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4691.0	10687.2	17730.2	25912.1

Table 4-19 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 3% demand growth and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-3												
4	3-4												
6		2-3											
8		3-4											
10			2-3										
12			3-4										
13				2-3									
14					2-3								
15				3-4	3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4	2-3 3-4
Total Investment (10^3 US$)	4503.1	3440.0	2724.8	2287.8	2207.2	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1	2133.1
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28382.4	85147.2	153300.0	234154.8	326923.2
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	21.60	35.0	48.6	62.2
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2838.2	8514.7	15330	23415.5	32692.3

Table 4-20 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 1% demand growth and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1													
5	2-4												
15	3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4
Total Investment (10^3 US$)	1679.6	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	3373.6	3373.6	3373.6	3373.6
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44500.8	105645.6	178704.0	264508.2	362664.0
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.7	26.8	40.8	54.9	69.0
Cost of Lost Revenue (10^3US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4450.1	10564.6	17870.4	26450.8	36266.4

Table 4-21 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 1% demand growth and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1													
5	2-4												
15	3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4	2-4 3-4
Total Investment (10^3 US$)	1679.6	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	1094.0	4242.4	4242.4	5029.6	5029.6	5029.6
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7174.4	59392.8	124567.2	202356.0	292934.4	396302.4
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	16.95	31.60	46.2	60.8	75.4
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	717.4	5939.3	12456.7	20235.6	29293.4	39630.2

Table 4-22 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 11 with 2% demand reduction and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	No Reinforcements Required												
Total Investment (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13797.0	67977.6	135210.6	215934.0	300643.2	415749.6
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	19.40	34.30	49.3	62.4	79.1
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1379.7	6797.8	13521.1	21593.4	30064.3	41575.0

Table 4-23 – Scheduling of new branches required along the 15 year planning with several quantities of DG connected at bus 12 with 2% demand reduction and adaptive control.

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1													
Total Investment (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4204.8	54793.8	116508.0	188865.6	272786.4
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.20	13.90	26.6	39.2	51.9
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.5	5479.4	11650.8	18886.6	27278.6

4.5.5 Locational impacts of DG

Initial studies involved validating that controllable DG could defer investment and as such, required retaining the location of DG at bus 11. Attention subsequently moved towards locational impact on investment deferral. Connection of various quantities of DG was focused at bus 12. This maintained similarities to bus 11 for ease of comparison. For example, bus 12 is also at the end of a radial circuit and is in close proximity, however, the load characteristics are different to permit new comparable results. Displayed in Tables 4.9 and 4.17 are the scheduling of new branches required along the planning horizon for firm and controllable DG connected to bus 12 for the 5% demand growth case. The results show that location is a significant factor in investment deferral and that network parameters are of major importance. This is consistent with the results experienced for the 3% and 1% demand growth and show that bus 11 can accommodate more DG. The 2% demand reduction, however, encounters the opposite and bus 12 can accommodate marginally more DG. This is due to the increased voltage experienced at bus 11 compared with bus 12. The original load at bus 11 in the base year is 2.85MW whereas bus 12 has 0.81MW of demand connected. At lower quantities of DG, bus 12 has the greatest level of investment deferral, however, as DG increased this investment deferral dropped below the level realised at bus 11. This is primarily due to the difference in demand. The lower demand implies that a greater amount of generation will require transportation towards the GSP upstream to be exported and consumed elsewhere on the network. The physical threshold of the overhead lines then becomes a limiting factor.

Additional curtailment could be permitted to grant more generation to connect, however, this arguably is no longer efficient use of the generator and is signalling that reinforcements are required. The purpose of the enhanced expansion planning method is to allow for investment deferral where possible and thus allow additional access for DG when small quantities of control/curtailment are required. It is not ultimately intended for oversaturation of DG where large levels of curtailment are always required. Figure 4.14 presents the level of annual curtailment required to prevent system violation from increased levels of DG. It is clearly shown that from the graph that bus 11 has additional capacity for more DG compared to bus 12. The sharp increase in curtailment is that the difference between the available capacity and connected DG increases suddenly.

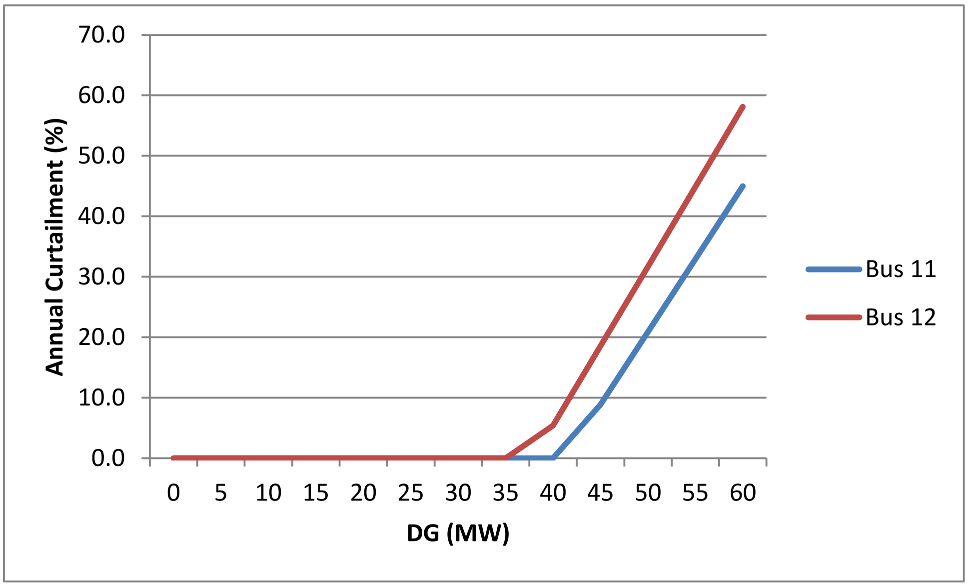

Figure 4-14 – Comparison of annual curtailment between bus 11 and bus 12 for the 5% demand growth case.

4.6 Chapter Four Summary

This chapter presents the idea behind the enhanced expansion planning method to provide an insight into the additional investment deferral possible by connecting actively managed DG as opposed to the regular 'fit and forget' type. The modified multistage analysis method incorporates adaptive control based on voltage and thermal management utilising sensitivity analysis. The existing expansion plan system has been extended to allow for the capabilities currently on offer by DG. Active and reactive power control can deal with thermal and voltage constraints that have occurred due to the upsurge in DG connections.

The model is based on two core functions, the multistage analysis which establishes the time along the planning horizon for when the reinforcements are required, to enable safe and secure operation. Secondly, the adaptive control algorithm executes sensitivity analysis to ascertain set points for active and/or reactive power to provide active control of the DG at times when firm export would otherwise trigger reinforcements.

The enhanced expansion planning method demonstrates its effectiveness in increasing investment deferral by operating adaptive control to mitigate thermal and voltage constraints. The scheme considers various scenarios to capture the uncertainty involved with planning. The approach is suitable for any DG unit, particularly renewable generation with the capabilities for active and reactive regulation. The worst-case scenarios employed to validate the scheme have substantial limitations and, to address this, a time series approach using realistic generation and demand data is developed in Chapter 5.

Chapter 5

Time Series Approach for New Expansion Planning Framework

5.1 Introduction

This chapter describes the philosophy behind the transition from considering four worst case scenarios to evaluating (more) realistic generation and demand values, which fluctuate during the course of the day and across the year. The new expansion planning framework is modified to allow renewable variability to be modelled and examined. Time series analysis is incorporated and two alternative methods employed to process the data is presented. First, a 5-day period of detailed time series data is investigated to appreciate the additional investment which can be deferred. Secondly, a technique employing correlation of the demand and generation is used to enable full representation year-round to capture all scenarios. Both approaches are reviewed and compared. Additionally, the correlation approach for incorporating demand side management (DSM) is examined in terms of its impact on reinforcements. The methods are validated utilising the 12-bus generic distribution network, employed in Chapter 4.

5.2 Time Series Approach

In Chapter 4, the expansion planning framework applied worst case scenarios to establish the level of investment deferral achieved by incorporating adaptive control to mitigate thermal and voltage constraints. Due to the rarity of occurrence for the worst case scenarios, in some circumstances planning for the extreme scenarios can prompt the requirement for reinforcement. Therefore, applying worst case scenarios is similar to the current passive design employed by DNOs, wherein, the additional capacity being built is seldom utilised. Considering more information on the occurrence of conditions may offer a more efficient method of designing and operating the distribution network, especially with the advances in technology.

The time series approaches presented in this chapter extends the expansion planning method one step further to consider the network under realistic operational conditions. It uses real patterns of generation and demand that may be seen by the distribution network. Generation and demand fluctuate according to both the local demand requirements and the available generation. Renewable DG is dependent on the energy resource and can be predicted while demand is somewhat more foreseeable. A key aim of this chapter was to identify if utilising actual demand and generation information as opposed to worst-case scenarios provides potential for further investment deferral.

5.2.1 Defining Settings of Time Series Approach

Demand data consists of either historic records obtained from monitoring equipment located at each bus within the distribution network or information inferred from historic weather patterns. Generally, the network operator registers data every 30 minutes and stores this for future analysis. In some instances, with latest technology the data is recorded every 10 minutes or more frequently. The generation data is gained similarly to the demand by either historic or hindcast methods. The key difference is that wind generation is evaluated from the wind speed available at the specific location as measured using an anemometer positioned on top of a mast, at a height similar to that of the proposed wind turbine. For the techniques employed, any reasonable measured or modelled data could be used. Ideally the data would have a short time step to ensure precision but this has associated data volume and processing burdens. Additionally, a time series of reasonable duration is important to capture the range of conditions that may be experienced. In assessing renewable energy resources this might be a period of 20 to 30 years but in distribution planning much shorter periods may be sufficient.

The wind resource and demand information was recorded in Scotland in 2003 [112] and has a time step of 10 minutes. The full year of demand and generation data is presented in Figure 5.1 and demonstrates that the demand reaches its minimum and maximum values on the odd occasion. Therefore, designing the network based on the extreme values alone may well underutilise the network's capacity. Also visible in Figure 5.1 is that the generation varies between full capacity and zero output, and this does not necessary complement the demand conditions. For example, at times of high demand it is not always the case that the generation will be operating at full capacity. Therefore, accommodating these variations into the planning process is vital to be able to design the distribution network for the future with increased penetration of DG and minimise the necessity for reinforcements.

For one whole year this would equate to 52,560 time steps and would take the simulation a vast amount of time to run. Reducing the time step to every hour would still require 8760 time steps to be analysed. As such, two approaches were used to drastically reduce the volume of time series data used and the computational effort. These are:

1. five-day periods taken from the winter and summer seasons; and
2. a method for correlating demand and generation across a year.

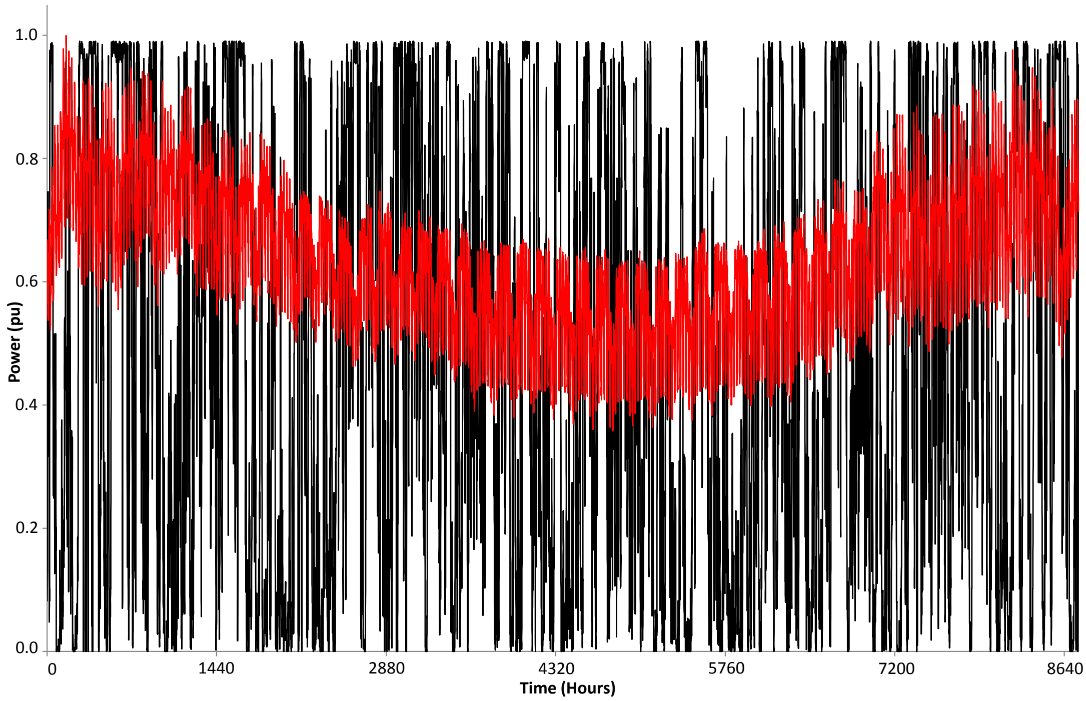

Figure 5-1 – Demand and wind generation profiles in Scotland in 2003.

5.2.2 Methodology

The method moves from examining a series of specific extreme cases to one which explicitly captures time periods representing the variation in demand and generation over a specific duration. Each time ‘step’ therefore has different demand and generation values to the preceding one and, after each time step, the network model is updated and load flow studies completed. Figure 5.2 displays the flow chart for the analysis to provide a visual aid to accompany the explanation. For each time step the multistage analysis identifies the cost effectiveness for each reinforcement option. Every single cost effectiveness value for each reinforcement option is accumulated within a global efficiency pool, for later comparison. Once the data has been analysed, the greatest cost effectiveness value experienced for each option is ascertained. This figure is stored for evaluation against the other reinforcements and compared to establish the least cost effectiveness value for elimination. This clarifies the reinforcement option that has the least impact on investment deferral. After elimination, the network is updated and the cycle performed repeatedly. This reveals if any further elimination can be accomplished. If any thermal or voltage violations occur, removal is not possible.

The analysis proceeds to cycle through the years in the time horizon reducing the year by one (as long as the base year is not yet reached). A drop in demand is exercised across the network, which represents the decline along the planning horizon and the cycle is activated once again. When no violations are present, the original asset is reinstated and deferral is achieved.

The implementation steps through the time periods one by one as this fitted most neatly with the earlier worst-case method. It could equally have been implemented such that each elimination case could have been tested with a series of time steps.
The same methodology is employed with the short time series and the correlated data although it should be noted that the latter does not represent a continuous time series in the true sense.

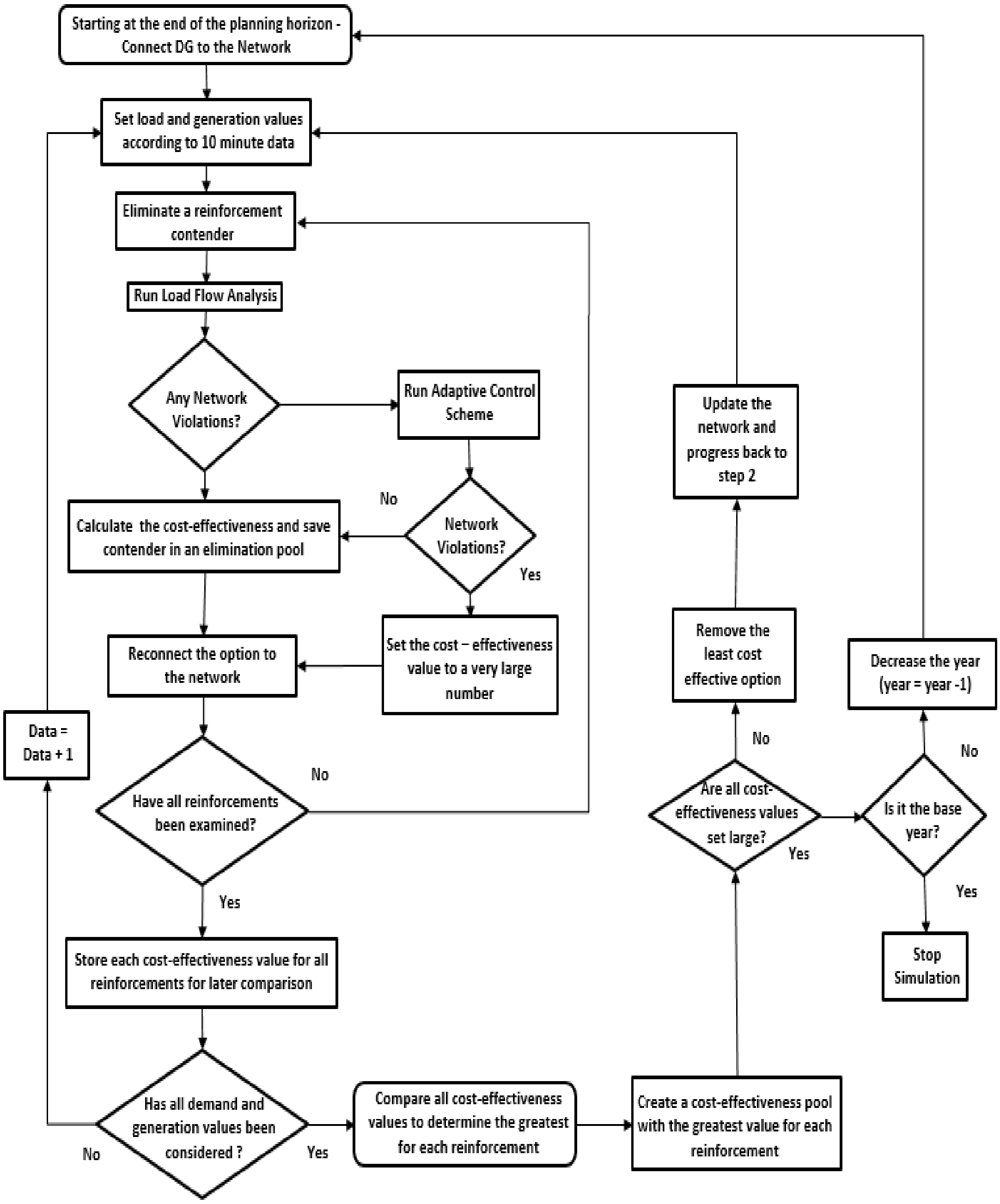

Figure 5-2 – Flow chart for time series analysis.

5.2.3 Demand and Generation Data – Full Times Series

Figure 5.3 displays the generation and demand data for the winter month of January 2003 and demonstrates that the maximum demand only occurs once and that the minimum never drops below 50%. The generation does not follow a particular profile, unlike the demand, but at times demonstrates production at the maximum level, which in turn would offset the local demand. Figure 5.4 shows the summer month of July 2003 and indicates a decrease in the level of demand compared with January. The demand only extends from a base load of approximately 40% to 65% of the maximum observed throughout 2003. Similarly, the generation, has no specific profile however, the maximum is observed less often.

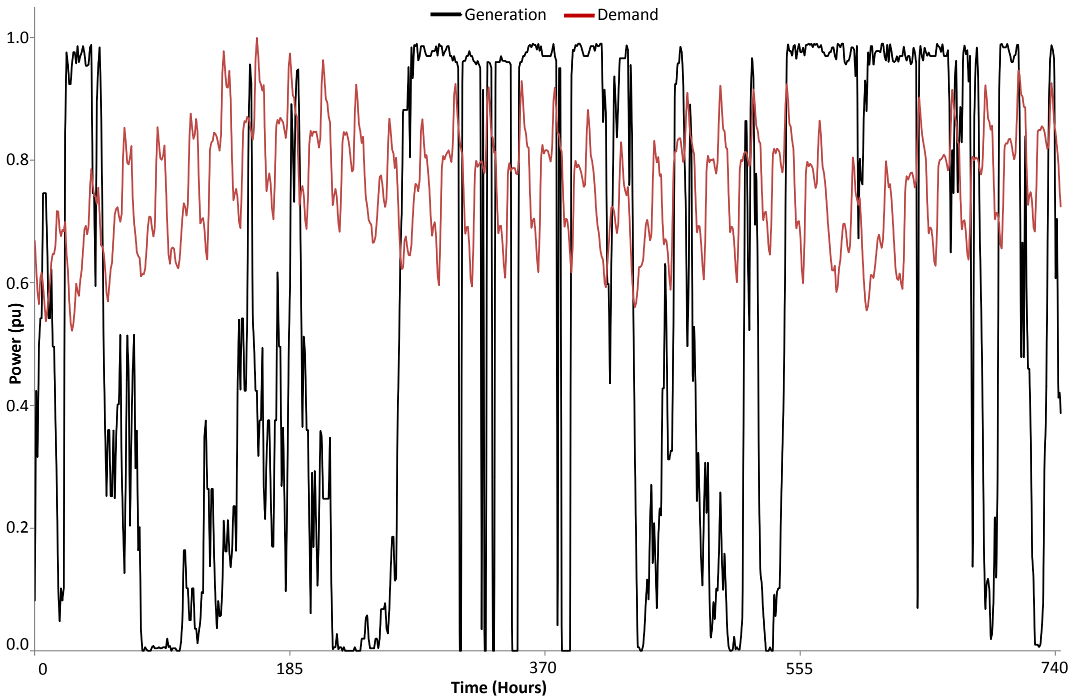

Figure 5-3 – Generation and demand time series for January 2003.

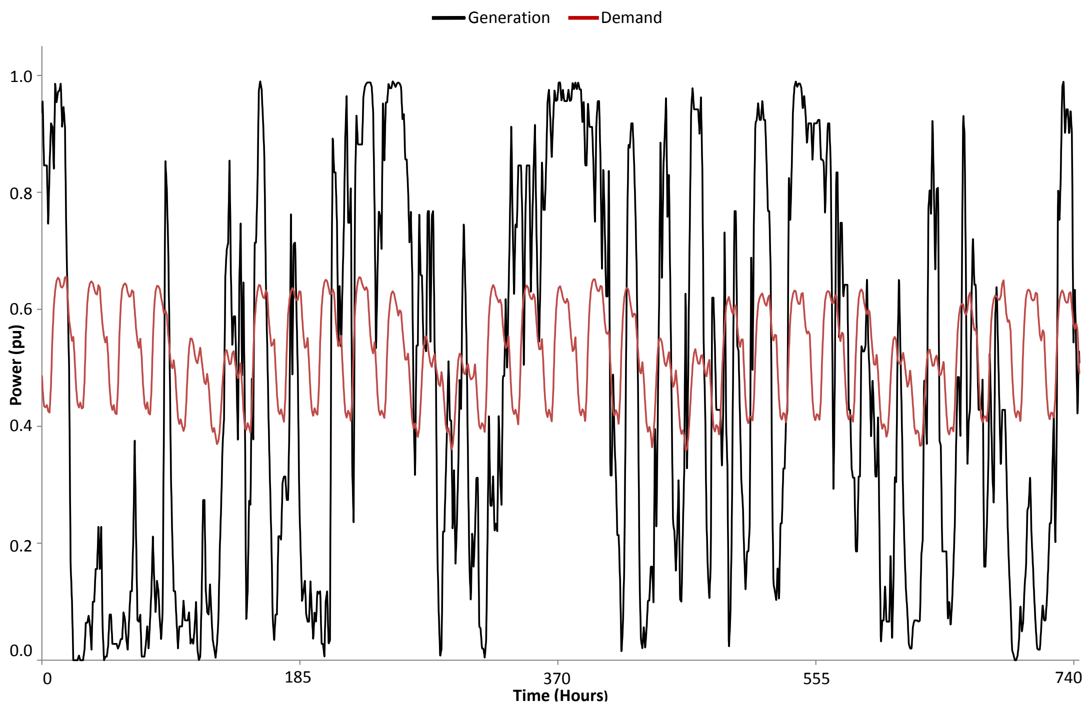

Figure 5-4 – Generation and demand time series for July 2003.

5.2.4 Demand and Generation Data – Correlation Method

The second method of evaluating the demand and generation profiles was to exploit the relationships between the data. By examining the coincidence(correlation) between demand and generation it is possible to allocate combinations of demand and generation to particular 'bins' or intervals and reduce the number of distinct combinations needing to be analysed. This technique was employed by Ochoa et al [135] in their ANM hosting capacity analysis and the same data was employed here. Bins are defined depending on the values of both the generation and demand outputs and range from 0 to 1.0 and 0.4 to 1.0 respectively in increments of 0.1. The maximum and minimum values are also retained to ensure the full range is captured. The values are rounded to the nearest tenth, for example, if the factor value is 0.434 this would belong in the 0.4 group. Whereas, if the value was 0.465, it would be rounded up and belong to the 0.5 group.

The data from 2003 is examined one time step at a time, and depending on the percentage of the maximum demand and generation, determines which bin increases in value. This is fulfilled for all 52,560 time stamps corresponding to one year or 8,760 hours. The end result provides a magnitude for each of the 77 defined bins. The number of similar combinations allocated to each bin defines the frequency of occurrence of those conditions.

Figure 5.5 presents the results from completing the correlation process and demonstrates a number of characteristics. The total maximum demand is 36.5MW and only increases above 34.7MW (95%) for approximately 9 hours (0.1%) of the whole year. The demand only ever falls below 16.4MW (45% of maximum) for approximately 700 hours (8%) of the year. Interestingly the correlation results suggest that for only 1,489 hours (or 17%) of the year does that the generation increases above 95% of the DG maximum rating. Exploring further demonstrates that under current DNO design principles maximum generation and minimum demand conditions only occur for approximately 0.4% (or 35 hours) of the overall time.

Exploiting the correlation of the demand and generation data allows for a reduction in the number of time periods required to analyse a greater time period, for example a year. Correlation avoids analysing similar demand and generation outputs repeatedly and selects the average values from each bin, to be examined collectively. A vast reduction in computational time is created whilst retaining all of the valuable data that the full time series approach provides.

There are potential downsides to this approach. The first is that the rounding of data reduces some of the precision of the underlying data; where there are thresholds applied, this is will likely affect the precise durations that these are exceeded. An example impact would be the amount of curtailment required. A second is that the temporal pattern is broken meaning that where sequential periods are important to outcomes, such as with energy storage, this might be an issue. In the present implementation of the analysis this is not a significant drawback.

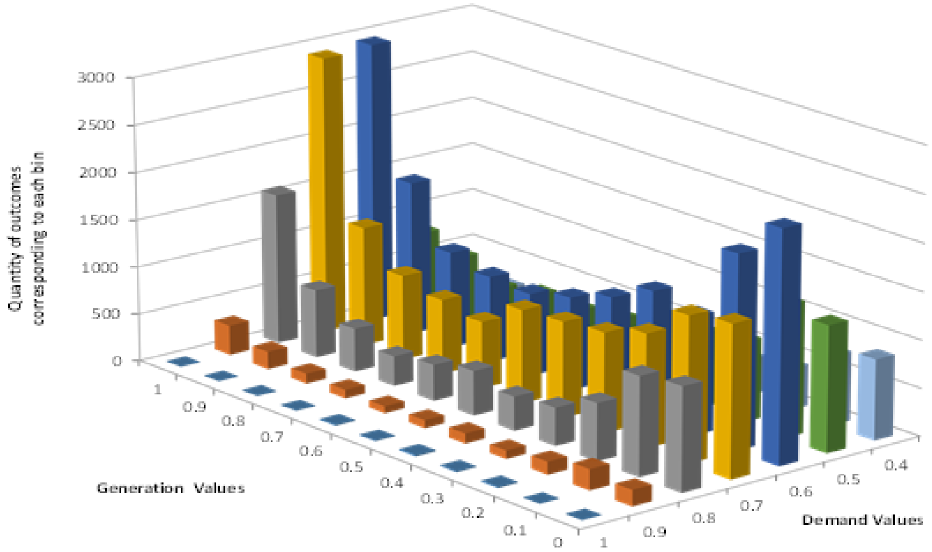

Figure 5-5 – Correlation of generation and demand data from 2003 (column value is occurrence of 10 minute combinations).

5.2.5 Time Series Analyses Conducted

The methodology is demonstrated in the following three sections. Section 5.3 shows the setup and results from the sample 5-day winter and summer 10 time series. Section 5.4 shows the results of analysis using the correlation method and Section 5.5 shows a variation of this that brings demand side management into the framework.

5.3 Time Series Analysis

The study is carried out on a 10 minute time step data over a 5-day period using the same 12-bus 33kV rural generic distribution network previously employed in Chapter 4, reproduced as Figure 5.6. An initial 5% annual demand growth for the duration of the planning horizon is retained to enable efficient comparison. Both setups of firm “fit and forget” and controllable DG are encountered to demonstrate the authenticity of the proposed procedures and to relate them to the outcomes from the scenario based approaches in Chapter 4. As an extension to the scenario based method, all the parameters remain identical for the 12-bus rural test network. However, instead of using the extreme case outputs from the generation and demand data, the time series approach utilises 10 minute data to run "real-time" analysis to provide a better understanding of the distribution network.

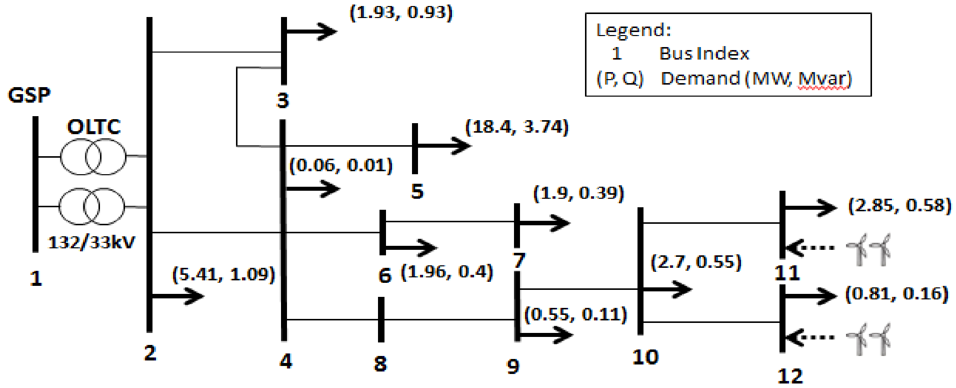

Figure 5-6 – Modified 12-Bus 33kV rural distribution network (UK GDS [133]).

5.3.1 Demand and Generation data

Two 5-day periods are examined. The first sequence of data is the from the winter season, 16th to 20th of January 2003, as in Figure 5.7. The second, shown in Figure 5.8 is for the summer season, 17th to 21st of July 2003. The selections are essentially arbitrary but were intended to show typical conditions. Figure 5.7, demonstrates that in January 2003 the demand only exceeds 90% of the maximum demand twice over a five day period. Generation is diverse and ranges from 0% to 100%, however, during this interval majority of the generation is situated someplace in between.

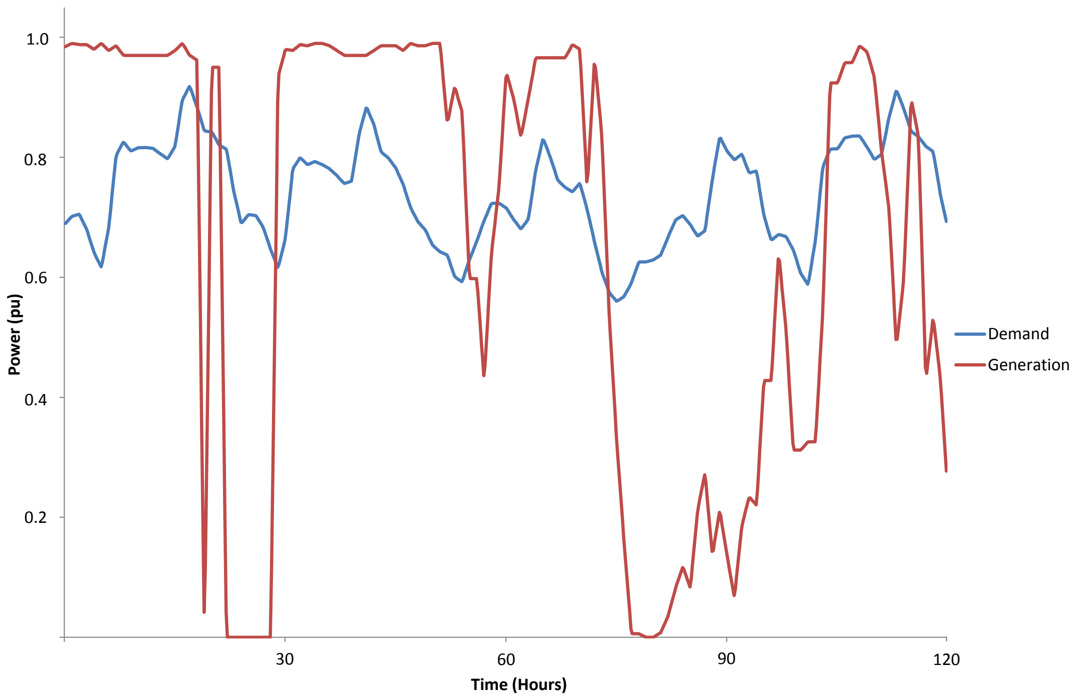

Figure 5-7 – 5 day generation and demand profile for winter season.

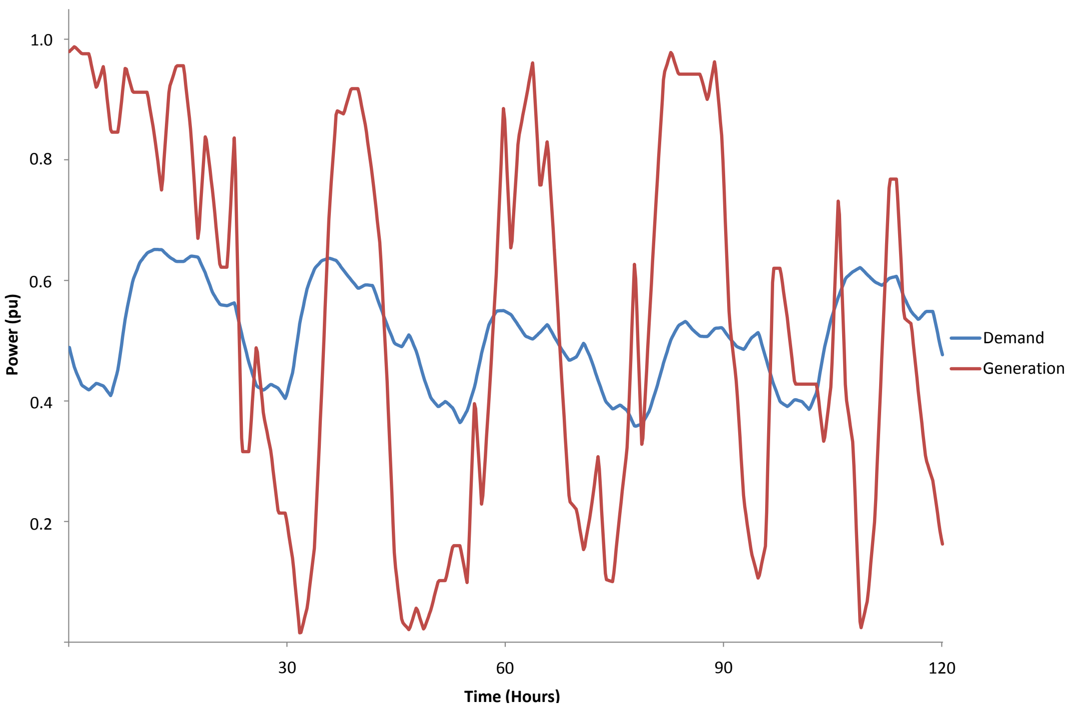

Figure 5-8 – 5 day generation and demand profile for summer season.

Figure 5.8 demonstrates the reduced maximum demand during the summer period. The demand over the period 17th – 21st of July never exceeds 65% of total maximum demand experienced. This makes a convincing case for considering an alternative approach to passive network planning design. The five day winter and summer period data is utilised to validate that applying a time series approach with real historic or forecast data provides an improved and transparent representation of the actual headroom available for additional capacity of DG and investment deferral.

5.3.2 Results

To enable ease of comparison against the original scenario based results, the simulations considered both “fit and forget” and controllable DG connections and 5% annual demand growth. Employing 10 minute time steps, execution of the expansion plan for the five day period (120 hours) across the range of DG requires 5 hours to complete. Although the analysis has been carried out for both January and July cases, the outcomes are broadly similar, although the values are different; as such only January is shown in detail.

The investment schedules for the fit-and-forget and controllable DG at bus 11 for the January profiles are shown in Tables 5.1 and 5.2, respectively. A notable effect of the use of the January time series is that the baseline investment cost with no DG present is different from the scenarios used Chapter 4. The cost drops from \$5.681 million to \$5.183 million. This is fundamentally the result of introducing a variable demand profile and specifically that the maximum demand experienced in this period is 93% of the overall maximum. This smaller level essentially means the expansion plan does not require the same level of network capacity at a specific point on the planning horizon to ensure voltage, thermal and security compliance. This is seen clearly, as while the same upgrades are required in the worst case scenarios (Tables 4.8 and 4.9), they are deferred by between 1 and 3 years, their order changes slightly and consequently the present value of the investments falls. However, it is important to note that should this analysis be applied on the system that experiences the full range of demand, the network would not be able to meet the real peak demand whilst ensuring asset and security compliance. In addition, the minimum demand levels exceed the minimum annual values and this will affect the least cost plan and the value of DG. That said the process and outcomes are illustrative and the trends and features are worth examining in more detail.

Both the fit-and-forget and controllable DG cases see the same decrease in investment cost as DG capacity increases up to and including 40 MW, resulting in a deferment benefit of 27%. The pattern of scheduling investments sees line 2-4 steadily deferred as DG increases, while deferment for others (2-3, 8-9 and 9-10) is more immediate and others remain roughly fixed (4-5). Beyond 40 MW, the fit-and-forget schedule sees line 10-11 reinforced in year 1 to accommodate export from the DG. This serves to significantly increase costs which increase by 61% ($2.28 million). For the controllable DG case, the investment schedule remains the same up to 60 MW at least. The impact of this is to require curtailment of the DG.

Table 5.2 shows the curtailment amount, percentage and resulting cost of lost revenue. It should be noted that the values given relate to the curtailment in the final year of the analysis, rather than a year-by-year or lifetime total. This was an oversight in the implementation as the analysis works backwards until the point at which an upgrade is required, it does not automatically analyse every year. As such, it was not possible to fully appraise the timing of the curtailment in each year (essential for discounted cash flow analysis) for direct comparison with the investment cost. This information could be produced by running a simulation for each yearly configuration and retaining the relevant data; this is an area for further work. Of further note, the monetary value for curtailment is not discounted to account for it being in year 15 which would reduce the present value to just under half. The values retained, however, offer a useful indicator of the relative size of the curtailment required in each instance. This shows that controllable DG at bus 11 is required to curtail 4.2% at 45 MW and 29.4% at 60 MW.

Tables 5.3 and 5.4 show the equivalent analysis for DG at bus 12. These indicate that the same investment schedule and costs occur as for bus 11 but only up to 30 MW before reinforcements are required to facilitate larger fit-and-forget DG. The full 10 MW less is related to the lower demand at bus 12 requiring more generation to be exported towards the GSP for a given level of capacity. The cost for reinforcing line 10-12 is greater due to the extra length involved, giving an initial 110% increase to accommodate an additional 5 MW ($4.19 million). The costs escalate further at 45, 50 and 55 MW as more lines are reinforced, culminating in a new line parallel to 10-12 which raises the cost to \$13.3 million. Using controllable DG therefore has a major impact as it allows DG to be connected without reinforcement at the expense of curtailment: 2.7% at 35 MW rising to 22% at 45 MW and 68% at 60 MW. This would appear to make bus 11 a more economical option for developers

In addition to location and DG size, demand growth has an impact on the outcomes. Table 5.5 shows summary information comparing the four demand growth cases with DG at each location. As with the worst-case scenarios in Chapter 4, the assumed demand growth has a major impact on the volume and schedule of reinforcement options with and without DG. This drops rapidly as the growth rate declines and there are no demand-led upgrades with declining demand. At bus 11, larger fit-and-forget DG can be accommodated without reinforcement with faster demand growth ranging from 30 MW for a 2% decrease to 40 MW for a 5% increase. At bus 12, there is no apparent difference between cases with a 30 MW fit-and-forget DG the largest that may be accommodated.

The deferment benefit for fit-and-forget DG is sensitive to the growth rate with benefit peaking almost 50% for 3% growth; this demonstrates that the 'lumpy' nature of investment means that modest changes in one assumption can have substantial impact. In this particular case, the schedule for 3% demand growth sees a need to upgrade line 2-3 and 3-4 while 1% growth forces upgrades of 2-4 and 3-4 and 5% growth requires all three; deferring line 2-3 has substantial benefits.

As DG gets larger there is some difference between the locations in terms of which and how many circuits are reinforced. For bus 12 these decline as growth rate falls but at bus 11 there is an upturn as demand decreases with extra reinforcement necessary to accommodate exports. The present value of the reinforcement is consistent across the demand levels as the same circuit is reinforced in year 1.

For bus 11 there is a clear pattern of curtailment increasing as demand growth falls. This is entirely logical as slower growth means that minimum demand levels are slower to rise implying larger amounts of curtailment for longer. At bus 12, the pattern is less clear with curtailment initially falling, then rising as demand decreases. This pattern is consistent across the range of DG and is due to the precise combination of assets upgraded ‘earlier’ in the time period.

5.3.3 Commentary

The analysis demonstrates that the method is feasible and can cope with very high resolution time series data. It was shown that after DG increases beyond the local demand requirements, generation-driven reinforcements are required. Depending on the amount of curtailment that would be tolerated, adaptive control allows additional DG capacity; keeping the indicative curtailment level below 5% allows an extra 5MW of DG capacity, but ultimately network reinforcements are still required to accommodate larger DG with moderate curtailment levels.

The July analysis showed broadly the same patterns of investment requirements and the value of DG and active control. The levels of demand in July are substantially lower, resulting in lower levels of investment at no-DG and low DG capacity cases, however, with maximum generation at similar levels to the January case, the generation-driven reinforcements tended to occur at lower levels of capacity. This reinforces an important consideration regarding the choice of time series conditions that the network needs to be designed for. It was clear that the chosen 5 days of data was insufficient to cover key conditions or ensure reasonable estimates of necessary curtailment volumes. While it might be feasible to run the analysis with a full year or more of data, the computational time would become excessive. As such, several options exist in which the approach could be refined to gain a better balance of capturing the range and variability of generation and demand and computational speed. These include:

- Increasing the time step to an hour would reduce the computational burden by a factor of six;

- Employing full weeks, fortnight or months as representative of seasons would improve the coverage of important conditions and improve the estimates of curtailment;
- Concatenating the 'representative' seasonal periods offers some measure of year round variability;
- Systematic reduction of the number of different conditions to be examined whilst preserving the variability.

The final approach was seen to offer the most scope for improving the analysis and this is examined further in the next section.

Table 5-1 – Investment schedule for range of DG capacities connected at bus 11 using January time series (5% demand growth, no control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1										10-11	10-11	10-11	10-11
2	2-4												
5		2-4											
8			2-4										
9													
10	3-4			2-4									
11	2-3				2-4								
11													
12		3-4											
13	4-5 9-10	4-5	4-5	4-5	4-5	2-4 4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9						2-4						
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5183.4	4414.7	4134.6	4012.0	3955.9	3853.0	3805.8	3761.4	3761.4	6041.4	6041.4	6041.4	6041.4

Table 5-2 – Investment schedule for range of DG capacities connected at bus 11 using January time series (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1													
2	2-4												
5		2-4											
8			2-4										
9													
10	3-4			2-4									
11	2-3				2-4								
11													
12		3-4											
13	4-5 9-10	4-5	4-5	4-5	4-5	2-4 4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9						2-4						
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5183.4	4414.7	4134.6	4012.0	3955.9	3853.0	3805.8	3761.4	3761.4	3761.4	3761.4	3761.4	3761.4
Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.2	467.3	881.9	1421.4
Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2	11.6	19.9	29.4
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.1	46.7	88.2	142.1

Table 5-3 – Investment schedule for range of DG capacities connected at bus 12 using January time series (5% demand growth, no control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1								10-12	10-12	9-10 10-12	8-9 9-10 10-12	8-9 9-10 10-12 *	8-9 9-10 10-12 *
2	2-4												
5		2-4											
8			2-4										
10	3-4			2-4									
11	2-3				2-4								
12		3-4											
13	4-5 9-10	4-5	4-5	4-5	4-5	2-4 4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9						2-4						
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9	2-3 2-4 3-4	2-3 2-4 3-4
Total Investment (10^3 US$)	5183.4	4414.7	4134.6	4012.0	3955.9	3853.0	3805.8	7690.7	7690.7	8823.7	9333.6	13269.9	13269.9

* Branch 10-12 requires an additional upgrade consisting of a second new overhead line

Table 5-4 – Investment schedule for range of DG capacities connected at bus 12 using January time series (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
2	2-4												
5		2-4											
8			2-4										
10	3-4			2-4									
11	2-3				2-4								
12		3-4											
13	4-5 9-10	4-5	4-5	4-5	4-5	2-4 4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9						2-4						
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5183.4	4414.7	4134.6	4012.0	3955.9	3853.0	3805.8	3761.4	3761.4	3761.4	3761.4	3761.4	3761.4
Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	383.9	808.6	1426.7	2091.9	3277.9
Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	11.9	22.3	35.4	47.2	67.8
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5	38.4	80.9	142.7	209.2	327.8

Table 5-5 – Investment requirement, deferment benefits and curtailment for range of demand growth rates for January time series.

	Annual Demand Growth Rate			
Bus 11	**5%**	**3%**	**1%**	**-2%**
Investment cost with no DG (10^3 $)	5183	4159	1534	0
Number of reinforcements with no DG	6	2	2	0
Max DG capacity before export reinforcement (MW)	40	40	35	30
Deferment benefit before export reinforcement (%)	-27%	-49%	-29%	0
Initial cost of reinforcement (10^3 $)	2280	2280	2280	2280
Number of lines reinforced for 50 MW fit-and-forget DG	3	1	1	2
Curtailed energy for controlled 50 MW DG (%)	11.6	12.4	16.3	29.8
Bus 12	**5%**	**3%**	**1%**	**-2%**
Investment cost with no DG (10^3 $)	5183	4159	1534	0
Number of reinforcements with no DG	6	2	2	0
Max DG capacity before export reinforcement (MW)	30	30	30	30
Deferment benefit before export reinforcement (%)	-27%	-49%	-29%	0
Initial cost of reinforcement (10^3 $)	3885	3936	3936	3936
Number of lines reinforced for 50 MW fit-and-forget DG	3	2	2	2
Curtailed energy for controlled 50 MW DG (%)	35.4	33	28.2	36.8

5.4 Correlation Method

The time series analysis requires over 5 hours of computational time to complete the examination of 120 hours of demand and generation data. There are 8760 hours in a whole year, meaning it would require approximately 365 hours of computational time to undertake the inspection of every time stamp. This is extremely time intensive, therefore, the correlation method is well suited to this type of study. As an alternative to analysing every time stamp, the correlation approach distributes the data into a series of 77 bins, and the average value of each bin and the extreme values are used in the expansion planning framework. This vastly reduces the total time required for running the simulation, however, it does decrease the level of detail provided. For example, if one bin with 3000 time stamps fails the security tests, the end result indicates that for 6% or 526 hours of the year, thermal or voltage violations occur. In reality, this may not always be true, but for the benefit of reducing the processing time, it is a drawback worth accepting. For the majority of occasions, this problem will arise where on the peripheries where the quantities of time steps are minimal.

5.4.1 Demand and Generation data

The 77 demand-generation bins are shown in Figure 5.5. In practice only 74 bins are required, as there is no data contained within 3 bins. Table 5.6 provides the generation and demand combinations used.

5.4.2 Results

The analysis again focusses on the 5% demand increase case. Tables 5.7 and 5.8 show the investment schedules for DG connected at bus 11, for fit-and-forget and controlled DG, respectively. What is immediately apparent is that for the no DG case, the investment schedules and overall investment amount match the worst-case scenarios in Chapter 4 (Tables 4.7). This is a reassuring and illuminating result as it demonstrates that where there is no DG, the critical maximum demand case drives the entire requirement for network reinforcement. This suggests that the historic planning approach was entirely reasonable.

Table 5-6 Correlation results containing generation and demand data from 2003.

Bin ID	Period Name	Load	Source	Bin ID	Period Name	Load	Source
1	Period_1	0.4	0	38	Period_38	0.7	0.4
2	Period_2	0.4	0.1	39	Period_39	0.7	0.5
3	Period_3	0.4	0.2	40	Period_40	0.7	0.6
4	Period_4	0.4	0.3	41	Period_41	0.7	0.7
5	Period_5	0.4	0.4	42	Period_42	0.7	0.8
6	Period_6	0.4	0.5	43	Period_43	0.7	0.9
7	Period_7	0.4	0.6	44	Period_44	0.7	1
8	Period_8	0.4	0.7	45	Period_45	0.8	0
9	Period_9	0.4	0.8	46	Period_46	0.8	0.1
10	Period_10	0.4	0.9	47	Period_47	0.8	0.2
11	Period_11	0.4	1	48	Period_48	0.8	0.3
12	Period_12	0.5	0	49	Period_49	0.8	0.4
13	Period_13	0.5	0.1	50	Period_50	0.8	0.5
14	Period_14	0.5	0.2	51	Period_51	0.8	0.6
15	Period_15	0.5	0.3	52	Period_52	0.8	0.7
16	Period_16	0.5	0.4	53	Period_53	0.8	0.8
17	Period_17	0.5	0.5	54	Period_54	0.8	0.9
18	Period_18	0.5	0.6	55	Period_55	0.8	1
19	Period_19	0.5	0.7	56	Period_56	0.9	0
20	Period_20	0.5	0.8	57	Period_57	0.9	0.1
21	Period_21	0.5	0.9	58	Period_58	0.9	0.2
22	Period_22	0.5	1	59	Period_59	0.9	0.3
23	Period_23	0.6	0	60	Period_60	0.9	0.4
24	Period_24	0.6	0.1	61	Period_61	0.9	0.5
25	Period_25	0.6	0.2	62	Period_62	0.9	0.6
26	Period_26	0.6	0.3	63	Period_63	0.9	0.7
27	Period_27	0.6	0.4	64	Period_64	0.9	0.8
28	Period_28	0.6	0.5	65	Period_65	0.9	0.9
29	Period_29	0.6	0.6	66	Period_66	0.9	1
30	Period_30	0.6	0.7	67	Period_67	1	0.1
31	Period_31	0.6	0.8	68	Period_68	1	0.2
32	Period_32	0.6	0.9	69	Period_69	1	0.3
33	Period_33	0.6	1	70	Period_70	1	0.4
34	Period_34	0.7	0	71	Period_71	1	0.5
35	Period_35	0.7	0.1	72	Period_72	1	0.6
36	Period_36	0.7	0.2	73	Period_73	1	0.7
37	Period_37	0.7	0.3	74	Period_74	1	0.8

For both cases with and without control, as DG is introduced the investment schedule progressively changes, upgrades are deferred and the required investment falls progressively to a minimum of $3.776 million with a 40 MW DG installed, representing a deferment benefit of 33%. Both control cases are identical up to this point and, furthermore, are identical to the values achieved with the worst case scenario (Table 4.8). Beyond 40 MW the fit-and-forget case sees a large increase in costs (up $2.2 million) due to the need to reinforce the line 10-11 to accommodate DG exports. Up to 55 MW, this matches the worst case schedule and with 60 MW DG there is a further increase in costs as the upgrade to line 9-10 is brought forward to year 1.

The case with control, however, sees no increase in investment costs (up to 60 MW at least) as the DG is progressively curtailed as the DG capacity increases. With a 45 MW DG, curtailment takes place at the minimum demand-maximum generation condition (40% demand-100% generation) and as the DG capacity rises curtailment occurs as more of the less extreme conditions result in overloading. As such, annual curtailment rises from 1.5% of potential generation at 45 MW to a more substantial 22.1% at 60 MW. At the lower end the cost of curtailment is relatively insubstantial.

For DG at bus 12 the picture is broadly similar (Tables 5.9 and 5.10). The investment schedule and costs generally precisely match the worst case scenario for the controlled case and with minor differences in the non-controlled situation. In the uncontrolled case the match is precise up to 30 MW and for 50 MW and above. For the 35 MW case the correlation method results in a an early upgrade to line 10-12 to allow DG export, raising the investment cost from $3.82 to $7.756 million. This will be due to the incorporation of minimum demand conditions. At higher DG capacity the investment costs are substantially greater than the equivalent capacity at bus 11, reaching £13.7 million at 60 MW.

The controlled and fit-and-forget cases differ for DG capacities above 30 MW where the significant upgrade costs are avoided completely and investment costs are minimised at $3.78 million. The investment schedule matches those for DG at bus 11, however control is required at 35 MW capacity rather than 45 MW at bus 11. Again the penalty is curtailment and this is substantially higher at bus 12: 0.9% at 35 MW rising to almost 60% at 60 MW. Like for like curtailment for 45 MW DG is 14.5% at bus 12 against 1.5% at bus 11.

The levels of curtailment seen are lower than in the five-day analysis in the previous section as a result of a lower average generation from examining the whole year rather than at typically windy winter period. This results in far fewer instances where reverse power flows occur and consequently less need for the adaptive control to act.

The impact of demand growth rates are seen in Table 5.11. The growth rate is again shown to strongly influence the necessary investment and in the case of bus 11 the pre-reinforcement fit-and-forget DG capacity. The same feature for the 3% demand cases are repeated, specifically the substantially higher deferment benefit available. DG at Bus 11 would be exposed to a steadily increasing amount of curtailment as demand growth falls and the picture is once again mixed at bus 12 with the 3% growth rate resulting in a substantially lower level of curtailment.

5.4.3 Commentary

Overall the correlation scheme provides advantages for planning of the distribution network where an increase in annual demand is expected. The breadth of conditions examined and the more realistic combinations of demand generation suggest sensible patterns of upgrades and levels of curtailment. It is clear however, that levels of curtailment rise quickly as DG capacity increases and a point will be reached where the option to reinforce the network will be considered more economic. The next section considers whether use of demand side management offers any benefits in this regard.

Table 5-7 – Investment schedule for range of DG capacities connected at bus 11 (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4								10-11	10-11	10-11	10-11	9-10 10-11
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11													
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	6056.0	6056.0	6056.0	6056.0	7182.3

Table 5-8 – Investment schedule for range of DG capacities connected at bus 11 (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4												
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11													
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	3776.0	3776.0	3776.0	3776.0	3776.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3970.6	19411.7	39470.5	77999.8
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	6.6	12.2	22.1
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	397.1	1941.2	3947.1	7780.0

Table 5-9 – Investment schedule for range of DG capacities connected at bus 12 (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4							10-12	10-12	10-12	9-10 10-12	8-9 9-10 10-12	8-9 9-10 10-12 *
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11													
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9	2-3 2-4 3-4	2-3 2-4 3-4
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	7756.4	7712.0	7712.0	9472.9	9983.1	13696.3

* Branch 10-12 requires an additional upgrade consisting of a second new overhead line

Table 5-10 – Investment schedule for range of DG capacities connected at bus 12 (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	2-4												
4		2-4											
6			2-4										
8	3-4			2-4									
9	2-3												
10					2-4								
11													
11	8-9					2-4	4-5	4-5	4-5	4-5	4-5	4-5	4-5
12	4-5 9-10	4-5	4-5	4-5	4-5	4-5							
13							2-4						
14		2-3 3-4 8-9 9-10						2-4					
15			2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5681.0	4608.3	4279.4	4141.7	4019.1	3963.0	3867.6	3820.4	3776.0	3776.0	3776.0	3776.0	3776.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1852.9	13176.4	38382.3	73823.4	129735.0	210705.4
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	5.6	14.5	25.1	40.1	59.7
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.3	1317.6	3838.2	7382.3	12973.5	21070.5

Table 5-11 – Investment requirement, deferment benefits and curtailment for range of demand growth rates for correlation method.

	Annual Demand Growth Rate			
Bus 11	**5%**	**3%**	**1%**	**-2%**
Investment cost with no DG (10^3 \$)	5681	4503	1680	0
Number of reinforcements with no DG	6	2	2	0
Max DG capacity before export reinforcement (MW)	35	35	35	30
Deferment benefit before export reinforcement (%)	33%	53%	35%	0
Initial cost of reinforcement (10^3 \$)	2236	2280	2280	2280
Number of lines reinforced for 50 MW fit-and-forget DG	1	1	1	2
Curtailed energy for controlled 50 MW DG (%)	6.6	10.5	11	18.4
Bus 12	**5%**	**3%**	**1%**	**-2%**
Investment cost with no DG (\$k)	5681	4503	1680	0
Number of reinforcements with no DG	6	2	2	0
Max DG capacity before export reinforcement (MW)	30	30	30	30
Deferment benefit before export reinforcement (%)	32%	53%	35%	0
Initial cost of reinforcement (\$k)	3889	3936	3936	3936
Number of lines reinforced for 50 MW fit-and-forget DG	2	2	2	2
Curtailed energy for controlled 50 MW DG (%)	25.1	10.9	24.2	25.7

5.5 Incorporation of DSM

It is clear from both the time series and correlation methods that while curtailment provides value in deferring reinforcement, eventually the DG becomes too large and reinforcement is required to allow continued export. This critical periods for this are minimum demand – which sets an upper limit on firm DG capacity – and maximum demand – which defines the point at which upgrades are required as the DG output cannot be guaranteed. Demand side management, however, offers scope to modulate high and low demand and the purpose of this section is to see how this might benefit both the DNO and DG owners.

A number of approaches were scoped to explore the requirements in terms of simplicity, impact on the wider methodology and time to implement.

1. The first considered control of individual loads to mitigate voltage and thermal constraints using the sensitivity approach used for the DG approach. This offered a potentially useful approach and largely reused algorithms from the

DG control. However, it introduced a second item to be controlled and would have required a form of coordination, potentially using droop control.

2. The second approach was a more 'centralised' effort using a single optimisation to define both required DG and DSM settings. This would have the advantage of handling multiple DG and DSM assets jointly but would effectively require a form of optimal power flow (OPF). While this could employ the OPF engine in PSSE this was felt to be too much of a shift in approach for the later stages of the research.
3. A third idea was to reduce the concept of DSM to its basics and consider it simply as a shift in the timing of a specific amount of consumption from high demand periods to low demand periods. This has the advantage of requiring no changes to the expansion methodology or control methods but would not be used directly in voltage and thermal constrain management.

One of the considerations with DSM is that by reducing load in one period it requires the deferred load to be increased in another. This may or may not be possible dependent on the extent of the delay required and the feasibility of a load increase at the later period due to the specific combinations of demand and DG output and the consequent risk of network constraints. All three methods could be implemented with full time series or the coincidence methods, although there would be a complete decoupling of the timing of the on/off actions with the coincidence method.

Given the advantages of the coincidence method in terms of capturing a wider range of conditions and the more realistic values for DG curtailment it was decided that the DSM method would employ the third approach by reallocating the demand in the highest and lowest demand bins to their nearest bins. In other words the values in the 100% demand bin would be allocated to the next bin down and the values lowest bin allocated to the next highest demand. This was done such that the upper demand limit was 90% and the lowest was 50%. This had the effect of reducing the number of bins to analyse from 77 to 55.

5.5.1 Results

The analysis again focusses on the 5% demand increase case. Figure 5.12 and 5.13 show the investment schedules with DSM for DG connected at bus 11, without and with control, respectively. The first item to note is that the investment schedule and costs are different from the standard correlation cases and those from the worst-case scenarios. The DSM cases see most upgrades deferred by at least a year. This is primarily as a result of the lower maximum demand arising from the action of DSM. The deferred upgrades have the effect of reducing the investment cost by \$0.37 or 6.5% for the no DG case. The lower costs persist right throughout the range of DG capacities although this reduces to 1.5% at 35 MW and approximately 0.25% above that.

The point at which a lack of DG control necessitates reinforcements is not changed by the DSM (40 MW) with costs rising by \$2.3 million beyond; however unlike the earlier fit-and-forget case without DSM there is no additional upgrade required for line 9-10 with 60 MW of DG. With DG control the investment cost is able to persist at \$3.761 million up to 60 MW.

The key impact of introducing DSM is on the curtailment of DG. The need to curtail is now only required with DG of 50 MW and above, some 5 MW greater than without DSM. The levels of curtailment is also substantially lower, approximately half for a 50 MW DG.

The impact of DSM is more significant at bus 12 as Tables 5.14 and 5.15 show. Again there is a general deferring of upgrades across the board resulting in lower investment costs. For the fit-and-forget case the investment costs are over 7% lower with a 5 MW DG and 2% for 30 MW DG. With fit-and-forget, the requirement to reinforce to facilitate exports is pushed back from 35 MW to 40 MW. The requirement to reinforce at higher DG levels remains but the cost is around 3% lower (at \$13.3 million at 60 MW).

With DG control the investment costs above 40 MW are fixed at a marginally lower level than the non-DSM case. Again the main impact of DSM is in lowering curtailment with need delayed until 40 MW and then only a very small amount (0.2%). Even at 50 MW the curtailment level is only 6%, around a quarter of the non-DSM case.

The impact of demand growth rates are seen in Table 5.16. The growth rate is again shown to strongly influence the necessary investment and the pre-reinforcement fit-and-forget DG capacity. The same features for the 3% demand cases are repeated, specifically the substantially higher deferment benefit available. DG at Bus 11 would be exposed to a steadily increasing amount of curtailment as demand growth falls and the picture is once again mixed at bus 12 with the 3% growth rate resulting in a substantially lower level of curtailment. Curtailment is substantially lower across the board.

5.5.2 Commentary

Although the approach to representing DSM is simple it illustrates clearly the impacts in terms of planning schedules, deferment benefit, additional DG and substantially reduced curtailment from ANM schemes. The assumption of DSM is a challenging one as for it to truly limit investment in network assets it must be reliable at key points in time, notably peak demand and also at time of low demand when generation output is high.

Table 5-12 – Investment schedule for range of DG capacities connected at bus 11 with DSM (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1									10-11	10-11	10-11	10-11	10-11
2	2-4												
6		2-4											
8													
9	3-4		2-4										
10	2-3												
11				2-4									
12					2-4								
13	4-5 9-10	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9	3-4				2-4							
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5306.6	4293.5	4071.5	3955.9	3902.9	3805.8	3761.4	3761.4	6041.4	6041.4	6041.4	6041.4	6041.4

Table 5-13 – Investment schedule for range of DG capacities connected at bus 11 with DSM (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1													
2	2-4												
6		2-4											
8													
9	3-4		2-4										
10	2-3												
11				2-4									
12					2-4								
13	4-5 9-10	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9	3-4				2-4							
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5306.6	4293.5	4071.5	3955.9	3902.9	3805.8	3761.4	3761.4	3761.4	3761.4	3761.4	3761.4	3761.4
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6727.7	15494.7	36834.0
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	6.7	14.6
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	672.8	1549.5	3683.4

Table 5-14 – Investment schedule for range of DG capacities connected at bus 12 with DSM (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1									10-12	10-12	9-10 10-12	8-9 9-10 10-12	8-9 9-10 10-12 *
2	2-4												
6		2-4											
8													
9	3-4		2-4										
10	2-3												
11				2-4									
12					2-4								
13	4-5 9-10	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9	3-4				2-4							
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5306.6	4293.5	4071.5	3955.9	3902.9	3805.8	3761.4	3761.4	7690.7	7690.7	8817.0	9327.2	13263.2

* Branch 10-12 requires an additional upgrade consisting of a second new overhead line

Table 5-15 – Investment schedule for range of DG capacities connected at bus 12 with DSM (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1													
2	2-4												
6		2-4											
8													
9	3-4		2-4										
10	2-3												
11				2-4									
12					2-4								
13	4-5 9-10	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5	4-5
14	8-9	3-4				2-4							
15		2-3 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10	2-3 2-4 3-4 8-9 9-10
Total Investment (10^3 US$)	5306.6	4293.5	4071.5	3955.9	3902.9	3805.8	3761.4	3761.4	3761.4	3761.4	3761.4	3761.4	3761.4
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	336.4	4919.6	13245.1	30064.3	55755.6
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.6	6.3	13.0	22.1
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.6	492.0	1324.5	3006.4	5575.6

Table 5-16 – Investment requirement, deferment benefits and curtailment for range of demand growth rates for correlation method with DSM.

	Annual Demand Growth Rate			
Bus 11	**5%**	**3%**	**1%**	**-2%**
Investment cost with no DG (10^3 $)	5301	3924	1344	0
Number of reinforcements with no DG	6	2	2	0
Max DG capacity before export reinforcement (MW)	35	40	35	30
Deferment benefit before export reinforcement (%)	29%	46%	19%	0
Initial cost of reinforcement (10^3 $)	2280	2280	2280	2280
Number of lines reinforced for 50 MW fit-and-forget DG	1	1	1	2
Curtailed energy for controlled 50 MW DG (%)	3.2	4.6	5.2	10.3
Bus 12	**5%**	**3%**	**1%**	**-2%**
Investment cost with no DG (10^3 $)	5301	3924	1344	0
Number of reinforcements with no DG	6	2	2	0
Max DG capacity before export reinforcement (MW)	35	35	35	30
Deferment benefit before export reinforcement (%)	29%	46%	19%	0
Initial cost of reinforcement (10^3 $)	3849	3149	3148	2280
Number of lines reinforced for 50 MW fit-and-forget DG	2	2	2	2
Curtailed energy for controlled 50 MW DG (%)	6.3	4.8	5.2	16.3

5.6 Chapter Five Summary

The methodology behind developing a time series model to enable the new expansion planning framework to incorporate real data was presented within this Chapter. Generation and demand data from a 5-day (120 hour) period during the winter period, and additionally, a process to enable the framework to consider 8760 hours (a year) of data. A correlation technique developed by a colleague enabled 8760 hours of data to be separated into 77 bins of usable information. The model utilises and extends the scenario based model presented in Chapter 4.

The model enables each time step from either the 5-day period or the correlated data to be analysed and determine where a voltage or thermal violation occurs when reinforcements are removed. This facilitates additional investment deferral and quantities of DG to be connected without the need for reinforcements. The results demonstrated that at lower levels of DG investment deferral could be increased by up to 50%. For the cases involving 5% or 3% annual demand growth, higher quantities of

DG observed small levels of increased investment deferral. This was primarily due to the DG delaying the reinforcements to the end of the planning horizon. If the planning horizon was extended, a further increase in investment deferral would have been established.

Chapter 6

Full Case Study

6.1 Introduction

The modified 12-bus generic distribution network employed to test the expansion planning framework has clearly shown that additional investment deferral is possible, although some curtailment is required. The concept of locally managing voltage and thermal constraints and incorporating that within the planning design, can identify where and when network reinforcement can be delayed or avoided. Further validation of the new framework is now carried for a real section of Scottish Power Energy Network's (SPEN) distribution network in East Ayrshire, Scotland to demonstrate that the new expansion planning framework is transferable and able to be implemented in most types of systems. To avoid excessive repetition the presentation of results is restricted to the coincidence approach incorporating DSM (as per Section 5.5).

6.2 Network, Load and Generation

The Coylton network is a small section of SPEN's semi-rural distribution network in East Ayrshire, Scotland. The data was primarily obtained from SPENs Long Term Development Statement (LTDS) [136] alongside some insights from their design team. Figure 6.1 provides the circuit diagram for the Coylton section of the network, reproduced from the LTDS, and the network parameters are provided in Appendix A. For purposes of demonstrating investment deferral, the interconnectors linking this network to neighbouring distribution networks have been omitted to create a standalone system. These interconnectors are considered as a normally open point (NOP) and are primarily used when maintenance or faults are experienced. To enable operation under N-1 security conditions, a few of the overhead lines components had to be altered, as normally secure operation is performed from the interconnectors.

The peak demand experienced at Coylton GSP is 47.8MW which is fed from the transmission network via twin 132/33kV transformers. This supplies four 33kV primary substations (buses 101, 310, 319, 323) which in turn supplies nine 11kV primary substations (buses 501 to 509) scattered across a large geographic area.

DG is connected to three of the 33kV primaries (310, 319 and 323) to enable evaluation of locational impact on a real network and the effects on the level of investment deferral and active power curtailment. The generation and demand profiles applied are the same Scottish profiles found in Chapter 5. No information was available from SPEN due to client confidentially, however, the method remains valid regardless of the data used and the results are indicative that the new expansion planning framework increases investment deferment. The correlation method incorporating DSM is utilised to reduce the computational burden.

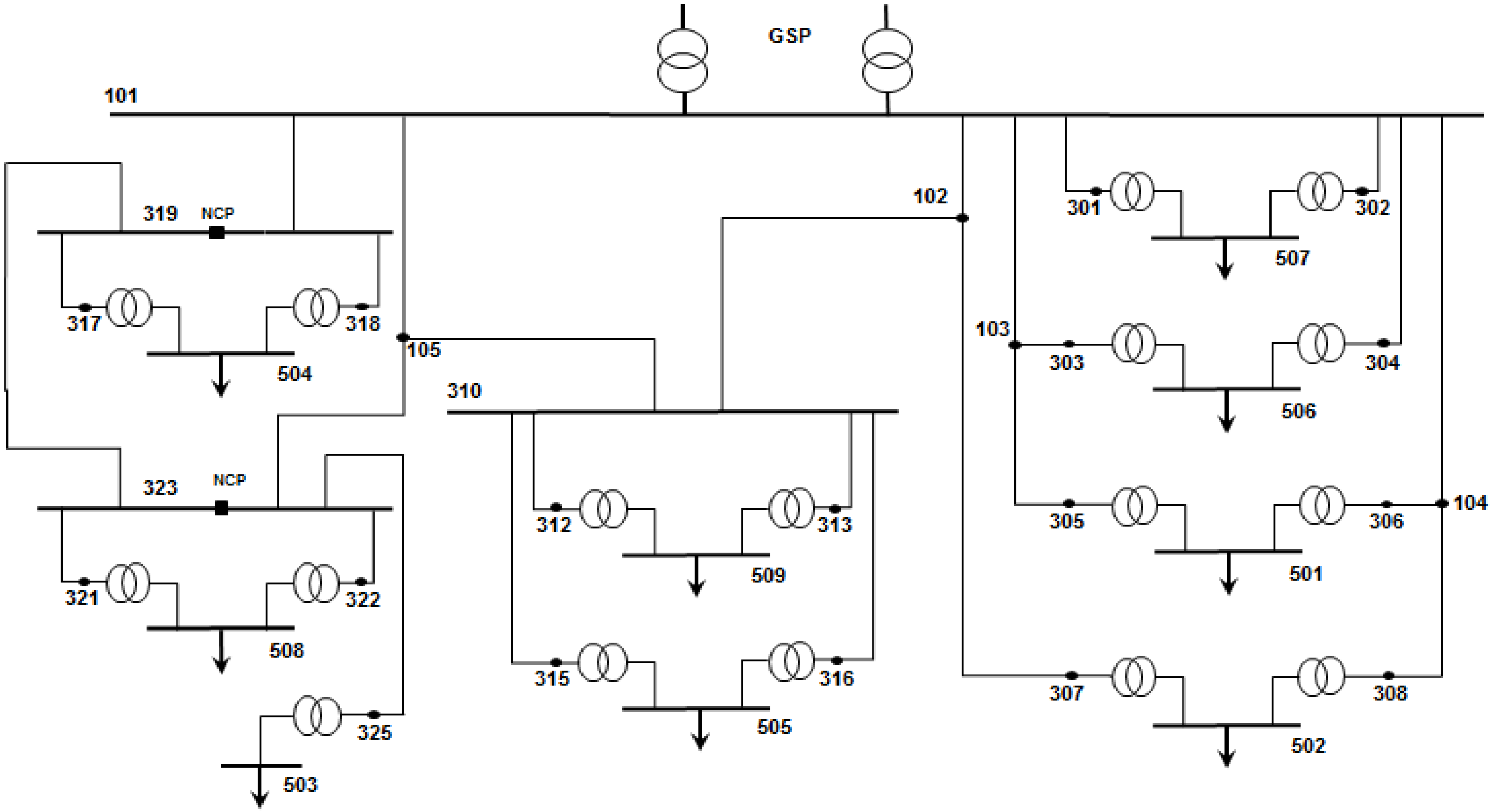

Figure 6-1 – SPENs Coylton Network in East Ayrshire, Scotland [136].

6.3 Results

The analysis focusses on the 5% demand growth case. Over 15 years will more than double the demand to 99.4MW in year 15. Table 6.1 presents the year that each reinforcement is required and the PV cost without DG.

Table 6-1 – Scheduling of new branches required along the 15 year plan with no DG connected and 5% annual demand growth.

Branch	Asset	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
101-102	OHL	Upgrade	2 x 60	120	11.5	5	2062.43
101-103	OHL	Parallel	1 x 35	96	2.29	7	146.21
101-104	OHL	Upgrade	1 x 60	120	11.6	5	1040.18
101-105	OHL	Upgrade	2 x 60	120	6.29	2	1343.54
101-304	OHL	Parallel	1 x 35	96	2.78	12	132.63
101-319	OHL	Parallel	1 x 35	96	8.01	3	645.63
102-106	OHL	Parallel	1 x 35	96	8.48	8	510.76
102-307	OHL	Parallel	1 x 35	96	3.14	11	158.79
103-303	OHL	Parallel	1 x 35	96	0.7	12	33.40
104-308	OHL	Parallel	1 x 35	96	1.71	11	86.48
105-310	OHL	Parallel	1 x 35	96	14	7	893.84
105-323	OHL	Parallel	1 x 35	96	6.25	1	566.04
310-315	OHL	Parallel	1 x 35	96	15.4	12	734.72
						Total	8354.65

The total cost in present value for reinforcements in this case is US$ 8.35m. Five reinforcements are required between years 1 and 5. Three reinforcements are required in years 7 and 8, the remaining are required in years 11 and 12. These are a mixture of upgrades and paralleling OHL.

Tables 6.2 and 6.3 show the investment schedule for DG connected at bus 310, for fit-and-forget and controlled DG, respectively. For both cases with and without control, as DG is introduced the investment schedule progressively changes, reinforcements are deferred and the required investment falls in a similar manner to the results experienced in Chapters 4 and 5. The investment progressively falls to a minimum of \$6.615 million with a 30 MW DG installed, representing a deferment benefit of 21%. Both control cases are identical up to this point. Beyond 30 MW the fit-and-forget case sees an increase in costs (up to \$1.6 million) due to the need to reinforce, initially line

102-106, then 101-102 and finally lines 101-105 and 105-310 to accommodate DG exports.

The case with control, however, sees no increase in investment costs (up to 60 MW at least) as the DG is progressively curtailed as the DG capacity increases (similar results were apparent in Chapters 4 and 5). Curtailment is experienced for capacities of 35 MW up to 60 MW and the level of curtailment progressively increases. As such, annual curtailment rises from 0.1% of potential generation at 35 MW to a substantial 39.5% at 60 MW. Below 45 MW the cost of curtailment is relatively insubstantial.

For DG at bus 319 the picture is similar (Tables 6.4 and 6.5), however, the level of investment deferral is lower at 9% with a minimum cost of $7.638 million, some $1 million higher than bus 310. This is primarily due to the lines that can be deferred connecting to bus 319, are shorter than the lines affected by DG at bus 310. With controllable DG, higher curtailment figures are seen compared with bus 310. This would be expected as the demand is slightly lower and accordingly, as the capacity for DG decreases requiring additional curtailment to manage overloading at the minimum demand-maximum generation conditions. As such, annual curtailment rises from 1.4% at 35 MW to a more substantial 68.6% at 60 MW. Due to the shorter line lengths, the cost to reinforce the network to accommodate up to 60 MW of DG is $8.621 million. This is only 3.1% higher than the required investment where no DG is present. This would suggest that under high demand growth, reinforcement would deliver unconstrained export for large DG capacities for marginally more than that to accommodate no DG.

Tables 6.6 and 6.7 present the investment schedule for connecting DG at bus 323. The level of investment deferral is slightly higher than that seen at bus 319 but lower than bus 310. The required investment falls to $7.490 million with a 35 MW DG installed, representing a deferment benefit of 10%. Beyond 35 MW the fit-and-forget case sees an increase in investment up to $8.678 million (or 3.7%). The case with control sees no additional investment, however, a 0.6% curtailment rate is experienced for a 40 MW DG connection up to 21.1% for 60 MW of installed capacity. This would suggest that a slightly larger DG could be accommodated for modest amounts of curtailment with much larger amounts achievable only with reinforcement. Although the additional amount is only a few percent above the no DG requirement.

The impact of locating DG at different buses is shown in Table 6.8. The location of the DG strongly influences the necessary investment and curtailment, if required. The initial cost of reinforcements are marginally different but the curtailed energy experienced at 50 MW DG varies substantially.

6.4 Commentary

The analysis demonstrates that the expansion planning framework is interchangeable between different network arrangements. It has shown that dependent on the location of installation, the investment deferral varies. The level of curtailment increases while DG rises and is dependent on the quantity of spare capacity seen at the point of connection. An extra 5 MW of DG capacity could easily be accommodated with an insignificant level of curtailment. This does not only bring the investment required down but also accelerates the time for connection.

Table 6-2 – Investment schedule for range of DG capacities connected at bus 310 with DSM (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
0								**102-106**	**102-106**	**101-102** **102-106**	**101-102** **102-106**	**101-102** **102-106** **105-310**	**101-102** **101-105** **102-106** **105-310**
1	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323
2	**101-105**												
3	101-319	**101-105** 101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319
4			**101-105**										
5	**101-102** 101-104	101-104	101-104	101-104 **101-105**	101-104	101-104	101-104	101-104	101-104	101-104	101-104	101-104	101-104
6		**101-102**			**101-105**								
7	101-103 **105-310**	101-103	**101-102** 101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103
8	**102-106**	**105-310**		**101-102**		**101-105**							
10		**102-106**	**105-310**		**101-102**		**101-105**	**101-105**	**101-105**	**101-105**	**101-105**	**101-105**	
11	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308
12	101-304 103-303 310-315	101-304 103-303 310-315	101-304 **102-106** 103-303 310-315	101-304 103-303 **105-310** 310-315	101-304 103-303 310-315	**101-102** 101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315
13					**105-310**		**101-102**						
14				**102-106**		**105-310**	**105-310**						
15					**102-106**	**102-106**	**102-106**	**101-102** **105-310**	**101-102** **105-310**	**105-310**	**105-310**		
Total Investment (10^3 US$)	8354.7	8111.3	7730.4	7431.8	7119.3	6797.0	6615.2	6913.6	6913.6	8521.9	8521.9	9305.1	9971.8

Table 6-3 – Investment schedule for range of DG capacities connected at bus 310 with DSM (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323	105-323
2	**101-105**												
3	101-319	**101-105** 101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319	101-319
4			**101-105**										
5	**101-102** 101-104	101-104	101-104	101-104 **101-105**	101-104	101-104	101-104	101-104	101-104	101-104	101-104	101-104	101-104
6		**101-102**			**101-105**								
7	101-103 **105-310**	101-103	**101-102** 101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103	101-103
8	**102-106**	**105-310**		**101-102**		**101-105**							
10		**102-106**	**105-310**		**101-102**		**101-105**	**101-105**	**101-105**	**101-105**	**101-105**	**101-105**	**101-105**
11	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308
12	101-304 103-303 310-315	101-304 103-303 310-315	101-304 **102-106** 103-303 310-315	101-304 103-303 **105-310** 310-315	101-304 103-303 310-315	**101-102** 101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315
13					**105-310**		**101-102**						
14				**102-106**		**105-310**	**105-310**						
15					**102-106**	**102-106**	**102-106**	**101-102** **102-106** **105-310**	**101-102** **102-106** **105-310**	**101-102** **102-106** **105-310**	**101-102** **102-106** **105-310**	**101-102** **102-106** **105-310**	**101-102** **102-106** **105-310**
Total Investment (10^3 US$)	8354.7	8111.3	7730.4	7431.8	7119.3	6797.0	6615.2	6615.2	6615.2	6615.2	6615.2	6615.2	6615.2
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	147.2	4036.6	13055.9	30695.0	56659.7	99653.8
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.4	6.9	14.6	24.5	39.5
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	403.7	1305.6	3069.5	5666	9965.4

Table 6-4 – Investment schedule for range of DG capacities connected at bus 319 with DSM (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
0								**105-323**	**105-323**	**105-323**	**101 -105** **105-323**	**101 -105** **105-323**	**101 -105** **105-323**
1	**105-323**												
2	**101-105**												
3	**101-319**	**101-105**									**101-319**	**101-319**	**101-319**
4		**101-319** **105-323**	**101-105** **101-319**										
5	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104	101-102 101-104	101-102 101-104
6				**101-105**									
7	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 **101-105** 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310
8	102-106	102-106	102-106 **105-323**	102-106	102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	102-106	102-106	102-106
10													
11	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308 **105-323**	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308
12	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315
15					**105-323**	**105-323**	**105-323**						
Total Investment (10^3 US$)	8354.7	8154.3	7980.7	7820.8	7694.8	7638.0	7638.0	7987.7	7987.7	7987.7	8621.1	8621.1	8621.1

Table 6-5 – Investment schedule for range of DG capacities connected at bus 319 with DSM (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	**105-323**												
2	**101-105**												
3	**101-319**	**101-105**											
4		**101-319** **105-323**	**101-105** **101-319**										
5	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**	101-102 101-104 **101-319**
6				**101-105**									
7	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 **101-105** 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310
8	102-106	102-106	102-106 **105-323**	102-106	102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106
10													
11	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308 **105-323**	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308
12	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315
15					**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**
Total Investment (10^3 US$)	8354.7	8154.3	7980.7	7820.8	7694.8	7638.0	7638.0	7638.0	7638.0	7638.0	7638.0	7638.0	7638.0
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2060.4	9923.3	24797.3	51719.0	80711.1	173069.6
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	5.9	13.1	24.6	34.9	68.6
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	992.3	2479.7	5171.9	8071.1	17307.0

Table 6-6 – Investment schedule for range of DG capacities connected at bus 323 with DSM (5% demand growth, fit-and-forget).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
0									**101-319**	**101-319**	**101-319** **105-323**	**101-319** **105-323**	**101-105** **101-319** **105-323**
1	**105-323**												
2	**101-105**	**105-323**											
3	**101-319**	**101-105**	**105-323**										
4		**101-319**	**101-105**	**105-323**									
5	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104 **101-105**	101-102 101-104 **105-323**	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104
6			**101-319**		**101-105**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**			
7	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 **101-105** 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310
8	102-106	102-106	102-106	**101-319** 102-106	102-106	102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	102-106
10													
11	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	**101-319** 102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308
12	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315
13						**101-319**							
15							**101-319**	**101-319**					
Total Investment (10^3 US$)	8354.7	8210.0	8041.0	7885.2	7717.1	7586.9	7490.4	7490.4	7938.5	7938.5	8115.5	8115.5	8678.0

Table 6-7 – Investment schedule for range of DG capacities connected at bus 323 with DSM (5% demand growth, with control).

Year Upgrade Required	DG Capacity (MW)												
	0	5	10	15	20	25	30	35	40	45	50	55	60
1	**105-323**												
2	**101-105**	**105-323**											
3	**101-319**	**101-105**	**105-323**										
4		**101-319**	**101-105**	**105-323**									
5	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104 **101-105**	101-102 101-104 **105-323**	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104	101-102 101-104
6			**101-319**		**101-105**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**	**105-323**
7	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 **101-105** 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310	101-103 105-310
8	102-106	102-106	102-106	**101-319** 102-106	102-106	102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106	**101-105** 102-106
10													
11	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	**101-319** 102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308	102-307 104-308
12	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315	101-304 103-303 310-315
13						**101-319**							
15							**101-319**	**101-319**	**101-319**	**101-319**	**101-319**	**101-319**	**101-319**
Total Investment (10^3 US$)	8354.7	8210.0	8041.0	7885.2	7717.1	7586.9	7490.4	7490.4	7490.4	7490.4	7490.4	7490.4	7490.4
Annual Curtailed Energy (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1009.2	6054.9	17029.4	35614.7	53232.8
Annual Curtailed Energy (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	3.2	8.1	15.4	21.1
Cost of Lost Revenue (10^3 US$)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.9	605.5	1702.9	3561.5	5323.3

Table 6-8 – Deferment benefits and curtailment for a range of bus locations for the East Ayrshire network.

	Bus		
5% Annual Demand Growth Rate	**310**	**319**	**323**
Max DG capacity before export reinforcement (MW)	34	31	37
Deferment benefit before export reinforcement (%)	20.8	8.6	10.3
Initial cost of reinforcement (10^3 \$)	0.298	0.349	0.448
Number of lines reinforced for 50 MW fit-and-forget DG	2	2	2
Curtailed energy for controlled 50 MW DG (%)	14.6	24.6	8.1

6.5 Chapter Six Summary

Chapter 6 demonstrates that the expansion planning framework developed within this thesis performs well on a real section of the UK distribution network. The generation and demand data applied in Chapter 5 was retained. The correlation method integrated with DSM was utilised enable a full year representation of data to be examined.

The results have confirmed that the expansion planning framework can be used to offer a signal to the DNO and developer towards the best planning scheme for inclusion of DG. The results demonstrated that at lower levels of DG investment deferral could be up to 20%. For cases with connection of large DG at buses 319 or 323, it would be more economically beneficial to invest on reinforcements as opposed to losing revenue from curtailment.

Chapter 7

Discussion and Conclusions

7.1 Introduction

This final chapter provides an overview of the key findings and discusses the main features, the contributions to knowledge and reflects on the limitations of the methods experienced throughout this thesis. To this end, consideration of future work is presented.

7.2 Thesis Summary

The research concentrated on developing a practical tool to enable quantification of adaptive control impacts on distribution network planning. This is a pivotal step towards assisting DNOs to transition towards operating an active network. The work is based on the desire for facilitating more renewable generation to support the UK's carbon emission reduction target. Factors such as annual demand growth, DG output, location and the ability to control the active and/or reactive power have been considered.

First, a review of distributed generation and their integration into distribution networks, current control strategies and efforts to incorporate active network management into planning approaches are presented in chapters 2 and 3. Chapter 2 offers an insight into different configurations found within the UK's distribution network and traditional design methods. Various types of DG technology alongside the drivers, benefits and impacts of integration are presented. Considerations behind the ongoing transition towards an active network are introduced. In Chapter 3, Active Network Management (ANM) is suggested as a method to actively manage distribution networks. The different types of ANM together with other control strategies are described. Activities currently being trialled are examined accompanied by an introduction to the concept of smart grids. Finally, the current network planning efforts employing active control are presented and critiqued.

In Chapter 4 an approach was introduced to enable controllable DG to exhibit its ability to defer generation-driven reinforcements. A new expansion planning framework was developed. It consists of a two stage process: firstly, a successive elimination model to determine the minimum reinforcements required to meet future demand. Secondly, a multistage planning analysis defines the connection schedules for the reinforcements within the planning horizon. Within the multistage planning analysis, a new adaptive control technique was incorporated to enable the deferment of generation-driven reinforcements to be analysed alongside demand-driven reinforcements. Capture of necessary curtailment was included to enable a more realistic assessment of controllable DG as an alternative to traditional reinforcements.

Chapter 5 concentrated on developing a time series method to capture demand and generation fluctuations experienced in the real world. The method established from Chapter 4 was enhanced to include analysis of realistic demand and generation data which together enabled the framework to provide an accurate connection schedule and a realistic curtailment assessment.

In Chapter 6 a fuller case study centred on a larger and more complex section of the distribution network in East Ayrshire, Scotland. It verified that the expansion planning framework could indeed provide results that controllable DG could defer investment and deliver reasonable levels of curtailment that would be required.

7.3 Discussions, Key Results and Contributions

The volume of variable DG currently pursing connection to the distribution network is creating many technical problems (largely voltage rise and line overloads), hindering their construction. The traditional approach employed by DNOs is to reinforce the network with new assets to provide greater capacity, which is often costly and underutilised. A “smarter” technique is to design the network considering controllable

DG as an alternative, potentially less expensive option. While DG contributes technical challenges for the DNO, in a great deal of cases it can provide positive outcomes for the network. These include, supporting network voltages, reducing network losses and delivering investment deferral, while enabling greater capacity for connection. This research is concerned with the latter two examples.

DG can defer investment as previously demonstrated by Wang *et al* [13]. However, incorporating adaptive control (or other ANM schemes) can improve investment deferral by mitigating the requirement for a number of generation-driven reinforcements. This does come at a cost, as some curtailment will be essential to maintain voltage and power flow profiles within statutory and physical limits. The level of curtailment is dependent on several factors involving the network parameters and configuration.

<u>Scenario Based Expansion Planning</u>

The scenario based expansion plan was developed by employing the worst case generation and demand profiles based on their maximum quantities. An adaptive control process was integrated to determine if control of the active and/or reactive power outputs could maintain the voltage and power flow within the desired limits to enable investment deferment. The validation results revealed that adaptive control provides additional investment deferral than cases with a firm “fit and forget” approach, which requires generation-driven reinforcements sooner. However, applying adaptive control requires a level of curtailment to facilitate the investment deferral. The intensity of curtailment is calculated and is provided as a percentage and therefore, the annual extent of energy lost can be determined. The scenario based model implies a considerably higher annual curtailment than would actually be experienced as there is no representation of time or varying value demand and generation. In reality, the generator only operates when the renewable resource (for instance wind) is available and this varies throughout the year.

Time Series Expansion Planning

The time series approach improves both the capability of the adaptive control and the curtailment capacity recorded by considering the actual demand and generation that applies throughout a year of operation. The data was recorded every 10 minutes and therefore contains 52,560 time stamps to be analysed. While great precision of curtailment volumes is observed, it is a large computational burden on the algorithm to examine each time step. An alternative method to analyse the data was considered, which established a relationship between the demand and generation data and considered similar demand/generation outcomes as 'one' to be examined. The 52,560 time stamps were condensed into an array of 77 'bins', significantly reducing the computational time for the algorithm. While the precision of the curtailment will be altered due to aggregation effects, this trade-off is regarded as acceptable as the error is modest and reduces the computational time. This potentially benefits DNOs by lessening the design engineer's workload. The results revealed that by employing the time series analysis, the curtailment percentage was reduced to more realistic levels, and demonstrated that low levels of curtailment outweighed the reinforcement costs. However, an optimum point is reached where the reinforcement costs equals the lost revenue from curtailing energy. Beyond this point it makes more financial sense to carry out the reinforcements and permit full export.

Implementation of Planning

A simple radial network and a more complex network were utilised to demonstrate the expansion planning framework performed as expected. Both networks experienced investment deferral with the addition of DG. The cases with controllable DG endured curtailment, which increased as DG grew. Location played an important role in defining the benefits of DG capacity and ANM.

Network planning is not as simple as determining whether the use of reinforcements or enduring curtailment are required. Many factors affect planning that are noneconomic (land, etc.). Beyond presumption that a DG of a given size must be deployed, further options are available, such as resizing the DG, using the electricity behind the meter or relocation. The expansion planning framework enables these options to be considered effortlessly.

Contribution

The expansion planning framework utilises a time series model to capture the variability of renewable generation, no other approach applies this technique from the literature examined. The framework demonstrates a toolkit with ANM embedded to prove that controllable DG can be successfully integrated to heavily congested distribution networks. It is believed that this work is novel in offering a more decentralised model of ANM within a planning framework. Incorporating DSM enables further benefits to be examined and the combination of both DSM and ANM contained within the framework is regarded as novel.

The toolkit considers renewable generation and demand variability alongside integrating ANM which motivates greater investment deferral and permits more DG connections. It is believed to be the first of its kind with a heuristic model developed to ensure a relatively simple and auditable process which can be 'seen' by decision-makers. Most other active distribution planning tools are essentially a "black-box" and this may limit their use in industry as planning engineers are unfamiliar with them. The expansion planning framework aims to address this issue.

7.4 Limitations of the Work

There were several limitations identified with the approach:

- The decentralised DG control uses a 6% threshold. With the use of a deadband in the transformer tap changing, this may end up with voltages marginally above or below intended set points. This is clearly seen in Sansawatt's work, so the benefit of ANM is expected to be slightly underestimated due to early 'trigger' of fail situations.

- The security model implemented is a two-way secure system i.e. it enables export to N-1 conditions, however, P2/6 only a requires demand-led secure system. The impact will be to promote upgrades in generation-led reinforcement, which might not be required in practice. This will tend to reduce the benefit of ANM, and therefore, increase the reinforcement schedule, narrowing the distinction between controlled and fit-and-forget DG.

- Implementation of the curtailment calculation only recovers the total for the final year and therefore, implies that curtailment would be higher in years 10 – 15. The value in reality would be much smaller, approximately only 48% of the nominal value due to the discount rate.

- The objective of the expansion planning framework ignores the cost of curtailment and losses. The focus was primarily on the point of view of the DNO to provide confidence that controllable DG can deliver network investment deferral. However, a whole system approach would be valuable too and will be discussed in the future work section. Arguably the cost of curtailment over the period of operation will require consideration from the developer. Whereas, the cost of network losses will ultimately be a concern for the DNO with respect to additional voltage profile issues and the requirement for high voltage transformer reinforcements. Both these parameters require incorporation into the expansion planning framework.

- The greedy heuristic method may not provide the optimal network planning solution however, method offers a transparent, functional and clear planning tool easily understood by DNOs and DG developers. Other approaches including mixed integer and stochastic metaheuristic also cannot guarantee optimality.

- The uncertainty considered within the new expansion planning framework was limited. It involved manually changing variables such as the location of DG, the annual demand growth and demand side management values. However, the framework will be suitable for stochastic treatment of these.

- The framework used a single DG unit assumed installed at the start of the horizon to demonstrate its capabilities but could easily be adapted to consider multiple DG units and alternative installation year.

- A relatively simple model for DSM is used which does not react to network constraints.

7.5 Future Work and Recommendations

Recommendations for further improvements to the expansion planning framework that would be valuable include:

- To test the sensitivity of the threshold choices within the decentralised control to observe whether a fixed limit as applied in the framework has an effect on underestimation.

- To remove the 2-way security component and compare the change in reinforcement schedule with demand-led security only. This could improve the investment deferral experienced, and may offer scope to incorporate elements of reliability analysis.

- To incorporate additional uncertainty, perhaps by running a Monte Carlo simulation or a similar algorithm which would provide a greater spread of conditions. The simpliest approach would be some form of mini-max regret analysis.

- To adjust the framework to require the simulation to be re-run after confirming the reinforcement schedule to more precisely calculate the level of curtailment experienced for each year. This could be further extended by:

- Building in the curtailment case as part of the design process, to optimise curtailment and reinforcement. This could be achieved by reversing the order of the algorithm in that evaluating elimination options and time periods. It would take longer but achieve this aim.
    - Include DG as an ‘expansion’ option within the SE method.
    - Incorporate a wider range of ANM options (e.g. centralised scheme) and more sophisticated DSM, storage, etc. This will require close control of timing of demand and generation.
    - Include multiple DG to consider influence on control.
    - Include DG to be connected further into the planning horizon.

- Verify the framework on a larger, more sophisticated model, incorporating greater levels of meshing and/or interconnection.

- Combine the cost of curtailment and network losses into the framework which would provide a whole system view. Incorporating the cost for the entire life span of the DG project would offer a transparent insight into which method, control or traditional reinforcement to advance with. Considering network losses will also raise any issues with abnormal voltage rise concerns or overheating of transformers.

7.6 Concluding Remarks

In this thesis, a new expansion planning framework considering a time series model incorporating adaptive control to capture the variability of generation and demand was developed. The scheme provides a plan for network operators to consider DG as an alternative to traditional reinforcements, thus creating investment deferral. The adaptive control enables DNOs to model the outcome that adjustment of the DGs output has on the network constraints. Incorporating adaptive control facilitates an increase in the potential DG that can be connected, which would otherwise trigger reinforcements. The framework also includes a curtailment assessment to enable developers the opportunity to assess whether investment in the infrastructure of the network is more cost-effective than losing revenue from curtailment.

The new expansion planning framework utilises industry standard power system programs to model and simulate operation of the network. This could be developed to include other programs initiating the opportunity for widespread use within the power industry. In addition, the author believes that the understanding and lessons learned from developing the expansion planning framework will benefit the power industry in making the transition towards utilising a planning method for active distribution network management.

Finally, in considering the hypothesis that,

> "Automated planning of distribution networks with active network management will be essential to realise the benefits of renewable distributed generation in terms of deferring or avoiding traditional network reinforcements."

the work has substantially proven the case.

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Appendix A: Network Data

In this appendix, the network data for the 12-bus 132/33kV and the Coylton rural distribution systems are provided. Network parameters of the modified 12-bus 132/33kV rural distribution network are given in Table A-1.

Table A-1 - Network data for 12-bus 132/32kV rural distribution network [131].

From bus	To bus	Line R (pu)	Line X (pu)	Rating (MVA)
2	3	0.198	0.446	25
2	4	0.187	0.299	45
3	4	0.216	0.287	20
4	5	0.0305	0.029	40
4	6	0.517	0.376	15
4	8	0.441	0.392	15
6	7	0.394	0.348	15
8	9	0.0728	0.1039	15
9	10	0.538	0.733	15
10	11	0.07812	0.02924	10
10	12	0.09754	0.07001	7.5

Network parameters of SPENs Coylton distribution network consists branch data given in Table A-2 and transformer data provided in Table A-3.

Table A-2 - Branch network data for SPENs Coylton distribution network [136].

From bus	To bus	Line R (pu)	Line X (pu)	Rating (MVA)
101	102	0.0922	0.3367	20
101	103	0.038	0.0657	15
101	104	0.1646	0.2876	20
101	105	0.0496	0.1809	20
101	301	0.2658	0.3617	10
101	302	0.2604	0.3462	10
101	304	0.0479	0.0654	10
101	319	0.0678	0.1619	18
102	106	0.0533	0.1843	20
102	307	0.04	0.065	10
103	303	0.0124	0.0182	10
103	305	0.3266	0.5641	10
104	306	0.2997	0.3994	8
104	308	0.0224	0.0354	10
105	107	0.1639	0.4148	12
105	323	0.1007	0.1841	15
106	310	0.0001	0.0001	15
107	310	0.0002	0.0002	10
310	312	0.0002	0.0001	12
310	313	0.0001	0.0001	12
310	315	0.2005	0.3191	8
310	316	0.2004	0.319	15
317	319	0	0.0001	60
318	319	0	0.0001	60
319	323	0.0988	0.167	10
321	323	0	0.0001	60
322	323	0	0.0001	60
323	325	0.1123	0.239	10
325	326	0.0679	0.1323	10

Table A-3 - Transformer network data for SPENs Coylton distribution network [136].

From bus	To bus	R (pu)	X (pu)	Rating (MVA)
301	501	0.05	0.999	24
302	501	0.05	0.999	24
303	502	0.0477	0.953	15
304	502	0.0477	0.957	15
305	503	0.05	0.999	10
306	503	0.05	0.999	10
307	504	0.0479	0.956	15
308	504	0.0479	0.956	15
312	505	0.05	1	12
313	505	0.05	1	12
315	506	0.0345	0.689	10
316	506	0.0345	0.689	10
317	507	0.0486	0.971	15
318	507	0.0486	0.971	15
321	508	0.0513	1.024	10
322	508	0.0513	1.024	10
326	509	0.0525	1.049	10

Appendix B: Publications

This section gives the author's publications in full. The conference publications are provided in a chronological order.

Conference Papers

1. S. Conner, G.P. Harrison, "A Direct Comparison of Various Active Network Management Techniques," presented at CIRED Workshop, Rome, 2014.
2. S. Conner, G.P. Harrison, "Demonstration of an Actively Managed Planning Approach for Connection of Renewable Generation," due to be presented at CIRED Conference, Glasgow, UK, 2017.

A DIRECT COMPARISON OF VARIOUS ACTIVE NETWORK MANAGEMENT TECHNIQUES

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ABSTRACT

Over the past decade a number of academic and commercial organisations have been developing techniques to actively manage the existing distribution system to avoid costly infrastructure upgrades. This paper discusses and evaluates five different types of Active Network Management technique. A brief description of each technique is presented. The comparison takes into account the amount of additional Distributed Generation and demand that could potentially be connected to the existing distribution network with no significant infrastructure improvements. Communication and monitoring equipment requirements are assessed and finally the total cost of implementing such schemes is evaluated.

INTRODUCTION

Increasing quantities of Distributed Generation (DG) are being connected to the distribution network at a rapid rate. Distribution Network Operators (DNOs) in partnership with industry and academia are researching methods of actively controlling the grid to save costly infrastructure alterations. Active Network Management (ANM) is believed to be an effective method to permit additional DG connection without costly infrastructure enhancements. There are several problems which need to be addressed, which include: power flow management; steady state voltage control; and automatic restoration. For ease of comparison this paper will only consider the problem involving Steady State Voltage Control. When connecting any type of generation to the distribution network, one major issue encountered is a variation in voltage and particularly, voltage rise. This voltage rise may be outwith the statutory limits which DNOs are required to comply with. A range of papers have been dedicated to this subject and several novel techniques are described in the next section.

ACTIVE NETWORK MANAGEMENT

AuRA-NMS is an autonomous regional active network management system which has been developed in the UK through a partnership involving several UK Universities, EDF Energy, Scottish Power and ABB [1]. The AuRA-NMS is a centralised ANM technique that requires monitoring equipment throughout the network in which it controls. A case-based reasoning (CBR) approach was developed by the University of Strathclyde and Durham University for voltage control [2]. CBR is said to have potential for a flexible and extensible approach to coordinated voltage control [2]. As an artificial intelligence system, CBR aims to solve a problem by re-using saved matched cases located in a case base library. The closest matched solution is tested online for success. If effective this result is then implemented into the control strategy. More details can be found in papers [2], [3] and [4].

The SuperTAPP n+ automatic Voltage Control Relay (VCR) is a decentralised scheme that has been tested on the UK distribution network. It is based on local measurements taken at the substation integrated with a state estimation system [5]. The current introduced into the network from the DG is estimated by the VCR; this is summed with the supply current measured at the feeders within the substation to provide an estimate of the total load. This value is used to set the Load Drop Compensation (LDC) and the set point voltage [6]. If voltage rise occurs due to increased amounts of DG, it is vital that the voltage is reduced. The estimated DG current is used to decrease the set point voltage. In depth details can be found in [6] and [7].

Optimal Power Flow (OPF) has potential as a centralised ANM technique. Information gathered at local nodes is used to solve the OPF problem. The OPF minimises DG curtailment to allow more generation to be connected to the network. Paper [8] explains the use of the OPF analysis to minimise curtailment within the thermal and voltage constraints. The role of the algorithm in [9] is to take full advantage of the total active power of controllable DG plant. Paper [10] demonstrates a Receding-Horizon OPF which uses network measurements and forecast data to allow network control decisions to be implemented with a degree of confidence that it won't lead to inappropriate control switching.

Now a commercial product in operation in the UK, GenAVC is a balance between a centralised and decentralised ANM scheme. The purpose is to maintain the voltages of the 11kV feeders connected to the primary transformer within the prescribed statutory limits [11]. Information collected from key remote measurement units (RMUs) forms the inputs to the GenAVC state estimation [12]. This computation obtains as true an image of the actual system state as possible without having to over provide RMUs which are costly and require additional communications.

Model Predictive Control (MPC) is an advanced process control method that originally was used in the process industries. More recently it has been incorporated into power system modelling to actively control the distribution network. MPC is described as an optimization based control scheme that uses dynamic modelling to determine control inputs that generates the best predicted performance of the network over a prediction horizon [13]. The theories and formulations of MPC are explained in [14].

BOOSTING DG CAPACITY

AuRA-NMS

The AuRA-NMS CBR voltage control technique has been tested on a real-time (RT) power network simulator. The test network consisted of a simplified model of a UK 40 busbar 11kV radial network incorporating two DG schemes and three transformers. A detailed description of the test network and testing procedures can be found in [15] and [3]. Figure 1 displays the voltage excursion at the DG locations and it can be seen that the CBR technique identified the voltage excursion and implanted a series of control strategies. These strategies are able to establish and instruct a set of control actions which are essential to removing an overvoltage and keep the voltage within statutory limits. This is possible by changing P and Q set points and controlling the on load tap changer (OLTC). Being able to control the voltage within the limits will allow additional DG and demand to be connected to the existing network without having to made substantial infrastructure upgrades. The actual figures for the volume of extra DG and demand that can be connected have not been published. Due to the amount of data sent back to the control algorithm it is thought to be fairly high.

SuperTAPP n+

A trial of the SuperTAPP n+ relay was carried out on the EDF Energy distribution network at a primary substation in the Horsham area in the south of England [16]. Results indicate that a maximum of 7 MW of DG could be connected utilising the SuperTAPP n+ relay, compared to the original 5 MW capacity. Due to the SuperTAPP n+ relay using local measurements and estimation techniques the full voltage headroom cannot be completely used as suitable safety limits need to be observed.

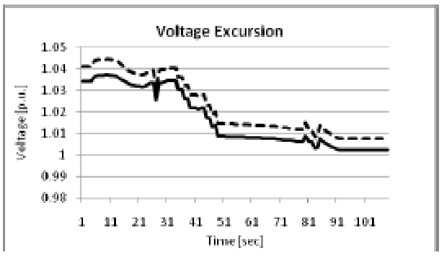

Figure 1 – Voltage excursion at DG1 (solid line) and DG2 (dashed line) busbars (limit at 1.03 p.u) [15].

OPF Approach

Simulation of the OPF approach was carried out on the 33 kV UK GDS EHV1 model network with multiple DG and resources, detailed data and procedures for testing on the network can be obtained in [17]. Utilising the control strategies of coordinated voltage control (CVC), adaptive power factor control (PFc) and energy curtailment as a last resort, headroom for connecting additional DG and demand is substantially increased. From results in [17] exploiting CVC, PFc and curtailment, the capacity of DG can be increased by three times the capacity versus passive management.

GenAVC

Testing of the GenAVC ANM system within the UK distribution network was achieved at the Steyning 33/11kV Primary Substation in West Sussex [18]. The results indicate that an existing landfill gas generator was able to increase output from 2 MW to 3 MW thus demonstrating a 50% increase in generation without any alteration to the existing distribution system [11], [17].

Model Predictive Control

Paper [19] demonstrates that the MPC strategy can achieve load shifting, plus using suitable predictions an improved matching of demand and supply can be accomplished. This will allow for more DG to be connected to the distribution network when demand and generation is high utilising the existing headroom that would otherwise be unexploited. However, when demand is low the MPC algorithm will continue to control the voltage levels using the power factor at the DG and finally curtailment of energy. The capacity benefit is not published but might be expected to be comparable to the OPF technique.

MONITORING AND COMMUNICATIONS

AuRA-NMS

Measurements are recorded and transmitted to the central controller from critical points throughout the network the ANM scheme controls. The critical points include DG connections and all main feeders. The measurements allow the CBR technique to perform the comparison of case features. It is assumed in [15] that the testing network has the necessary instrumentation. The communication requirements will depend on the type and location of the network. In urban locations an Ethernet interconnected in a local area network could be used which is relatively inexpensive, commonly available and allows high-speed data transfer and is, therefore, the preferred option. Rural installations will benefit from using a General Packet Radio Service (GPRS) router which enables communications using the GSM mobile phone network. This option is more expensive as ongoing costs are charged for transferring data over the GPRS network.

SuperTAPP n+

The SuperTAPP n+ relay uses existing Voltage Transformers (VTs) and Current Transformers (CTs) which are located in most substations. Each medium voltage transformer is measured and the data sent back to the relay via a CAN communication bus [20]. The only other monitoring equipment required is current measurements on the feeder which has DG connected to it. This is also local to the substation.

OPF Approach

In [9] a Supervisory Control and Data Acquisition (SCADA) system is proposed for measuring local data taken at key local nodes throughout the network, particularly DG sites and at other troublesome nodes. Remote Terminal Units (RTUs) take the local measurements and convert the signals to digital data, which is sent usually by telephone lines to the control centre.

Gen AVC

Measurements of both voltage and current are logged via a data acquisition unit. These values are transmitted to a control unit which is located in the primary substation via an Ethernet interconnected local area network connection if available. However, in remote parts of the country a GPRS router might be required which is more expensive. Also there is more vulnerability to the ongoing data transfer due to low redundancy within rural local GSM network coverage, signifying the possibility of loss of signal and data transfer. A detailed insight can be found in [11].

Model Predictive Control

Line flow, bus voltage information and switch status is measured by phase measurement units (PMUs) and the data is collected by Phasor Data Concentrators (PDCs) as described in [21]. The PDCs send the information via existing Ethernet interconnected local area network communication connections where available.

TOTAL COST

The cost of communications and monitoring equipment is one of the most significant factors in ANM alongside the development and upkeep of the software. The AuRA-NMS scheme is expected to be the most expensive option owing to the quantity and location of measurement apparatus required throughout the network for the control strategies to be implemented. In comparison the SuperTAPP n+ relay is the least expensive due to utilising existing measurement devices such as CTs and VTs within the local substation. The other three techniques have a range of outlays depending on the quantity of monitoring and therefore the type and volume of communication requirements. Table 1 demonstrates the level of total cost of each scheme alongside the amount of communications and monitoring equipment. The table also identifies the volume of additional DG/demand that could potentially be connected to the network.

DISCUSSION

Comparison of several different ANM techniques demonstrates that additional DG and demand can be connected to the network if more sophisticated control approaches are utilised. However, more information is required from within the network with communication and monitoring equipment bringing in associated costs. More DG can bring both beneficial and detrimental elements to DNOs, due largely to infrastructure investment. Depending on DG type, quantity and location, network upgrades could be deferred.

DNOs have a decision to make: to spend money on ANM methods that can actively control the network and make it much easier to manage or to upgrade the infrastructure that will allow additional DG and demand to be connected in the future. What is essential is that robust cost benefit evaluations are carried out to ensure that the implications are understood across the whole life cycle.

Table 1 – Classification of requirements and benefits

Type of ANM	Additional DG/Demand	Communications/Monitoring	Total Cost of Scheme
AuRA-NMS	Medium -High	Medium - High	High
SuperTAPP n+	Low	Low	Low
AC OPF Approach	Medium - High	Medium - High	High
GenAVC	Low – Medium	Low - Medium	Low – Medium
Model Predictive Control	Medium	Low – Medium	Medium

CONCLUSIONS

This paper presents five different ANM techniques which are either commercialised or in final stages of field testing. A comparison considered the amount of additional DG and demand that could potentially be connected to the network. Communication and monitoring requirements alongside the total cost for implementing each ANM was discussed.

ACKNOWLEDGEMENTS

This work is funded by an EPSRC Studentship and the School of Engineering, University of Edinburgh.

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DEMONSTRATION OF AN ACTIVELY MANAGED PLANNING APPROACH FOR CONNECTION OF RENEWABLE GENERATION

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ABSTRACT

U.K. carbon reduction targets have seen a rapid and sustained increase in renewable generation developers seeking connection to the distribution network. This paper presents through simulations, the positive results that can be seen by integrating Active Network Management (ANM) techniques into the network planning scheme. The method is devised to allow Distribution Network Operators (DNOs) to utilise the full available network capacity and as a result connect additional Distributed Generation (DG).

INTRODUCTION

To meet any increase in demand and/or generation under current planning practices typically requires network reinforcements. Controlling network constraints, such as, power flow limits and voltage variations, while maintaining sufficient Distributed Generation (DG) access, signifies one of the most important challenges [1]. Distribution Network Operators (DNOs) are investing time and money into implementing Active Network Management (ANM) solutions which will allow considerable amounts of DG to connect to existing networks while safeguarding physical power flow limits and statutory voltage limits are not exceeded.

To enable the use of ANM and increased levels of DG, new and novel planning procedures are required. The existing passive techniques are only suitable for the "fit and forget" approach which limits the capacity of DG able to gain connection. Moving to an actively managed planning scheme would allow more DG to be connected to the existing network and operate with real-time control of the active and reactive power output to mitigate constraints. If voltages and thermal constraints occur, the control mechanisms would be in place to maintain the network within a safe and secure environment. Employing network constraint management instead of reinforcing the infrastructure has the potential to save time and money.

This paper introduces an enhanced expansion planning method which integrates a multistage analysis process with an adaptive network control algorithm. Results from simulation of the enhanced expansion planning approach are presented.

EXPANSION PLANNING TECHNIQUES ON DISTRIBUTION NETWORKS

In planning the development of their networks and in integrating DG, DNOs have employed a passive approach, wherein the 'worst case' conditions drive the requirements for network capacity. Traditionally peak demand was the key condition but with DG minimum demand-maximum generation is normally critical in defining hosting capacity. In practice, these scenarios rarely exist, yet they drive the need for reinforcement. While 'automated' planning systems have not seen wide use in UK DNOs, there is substantial potential for dealing with the added complexity associated with greater DG capacities and variability.

Although focussed on peak demand conditions, [2] created an expansion planning scheme to determine whether DG could be used as an alternative to traditional reinforcement. It employed industry-standard software (PSSE) and the expansion planning analysis involved a successive elimination (SE) method combined with multistage planning. This was employed to determine the investment deferral benefit of DG.

The SE method is a heuristic method that overbuilds the network with a range of potential reinforcement options. Accounting for demand growth over the planning horizon, it then systematically tests the impact of removing reinforcement options. The least cost effective options are removed until any more removals would result in violation of the thermal and/or voltage limits. The final expansion plan to solely accommodate the increase in demand is now established.

The multistage planning component then defines the timing of each of the required reinforcements over the planning horizon. By inserting DG within the network, the approach allowed the level of investment deferral to be defined by deferring or avoiding traditional reinforcements. The value is calculated by reference to the present value cost for the reinforcement in the determined year. The investment deferral is calculated from subtracting the cost of reinforcement with DG from the cost with no connected DG.

The approach has been substantially enhanced to enable it to operate with variable generation and incorporate active network management systems.

PLANNING APPROACH FOR ACTIVE NETWORKS

The following approach is accomplished by integrating the existing multistage planning strategy together with an adaptive control approach for controlling voltage and thermal constraints [3]; both methods were developed at the University of Edinburgh. Introducing an adaptive control into the planning strategy allows DNOs to fully appreciate the potential actively controlled DG can bring to the planning and operation of the distribution network. Investment deferral is achieved by connecting actively managed DG strategically onto the network which helps delay reinforcements to the existing infrastructure.

The SE method is utilised to establish the minimum network required to function safely and securely with a fixed level of annual demand growth over a pre-defined planning horizon. The output from the SE method is employed within the multistage analysis to ascertain at what time along the planning horizon, the reinforcement is required. With no DG connected, the result details the present value (PV) cost for building out the reinforcements to maintain the network within the defined operational constraints. Including fixed DG offsets the increase in demand and warrants investment deferral. However, after the level of DG rises above the local demand or at times when local demand is low, network constraints occur. To mitigate this effect, including adaptively controllable DG will defer additional investment.

While a wide range of ANM control systems could be accommodated within the approach, the control scheme employed in this work is a decentralised method. It controls the active and/or reactive power output of the connected DG in real-time [3]. Control actions are identified once monitored data violates threshold values. Corrective actions are taken to maintain the voltage and power flow within the pre-defined limits. Real-time sensitivity analysis is applied to limit the level of curtailment or power factor control to maximise the output from DG. The voltage and power flow measurements are continually monitored to establish when control procedures can be restored to prevent unnecessary loss of renewable energy.

As an add on to the conventional multistage expansion planning method, adaptive control is considered at times when the voltage or thermal constraints are violated. Within the DG capabilities, power factor (PF) can be adjusted and active power can be curtailed. It has generally been the practice for DG to operate at unity

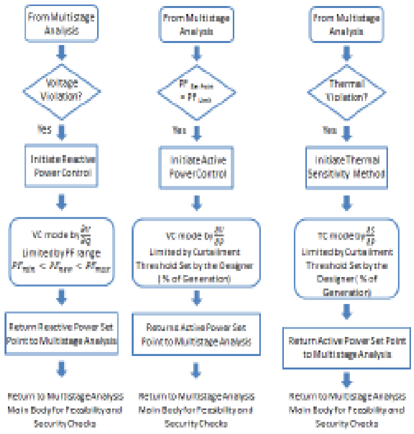

Figure 1 - Functional charts for reactive power, active power curtailment for both voltage and thermal control

power factor and at 100% of available generation. An alternative approach is to modify the reactive power for voltage variations issues and on occasion cutrail the active power to maintain both voltage and thermal constraints.

Within the multistage analysis, monitoring of the voltage and power flow against the pre-defined limits determines when voltage and thermal violations exist. Once it has been estblished that the voltage is beyond the statutory limits, the reactive power control is initiated. The new reactive power set point is defined by firstly calculating the variation of voltage for a 1MVar change. The reactive power required to reduce the voltage to within the limits is then estimated. The set point is returned to the main multistage analysis for further feasibility and security checks, as illustrated in the first chart in Figure 1.

Once the reactive power is at the maximum capability of the DG unit and if voltage violations still occur, active power curtailment is considered before regarding reinforcements as the only option. Active power curtailment for voltage control also uses the sensitivity analysis. However, the active power set point is calculated by obtaining the variation in voltage for a 1MW change. An estimation of the active power curtailment required to bring the voltage back within the limits is evaluated. The designer can stipulate a maximum level of curtailment if necessary as demonstrated in the middle chart of Figure 1.

Finally, consideration of active power curtailment for thermal constraints is very similar to the type for voltage control. Once a thermal violation has been identified, the calculation to determine the active power set point required to reduce the power flow to within the physical limit is computed. Firstly, the variation in power flow for

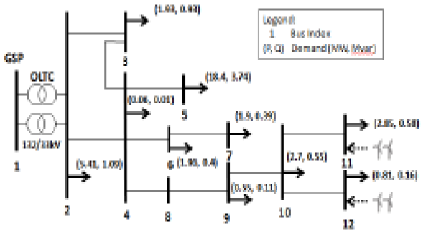

Figure 2 - 12Bus modified rural distribution network [4]

a 1MW reduction is calculated. This figure is applied to determine the minimum essential curtailment to reduce the power flow to below the limit. Likewise, the designer can specify the maximum level of curtailment as presented in the right hand chart in Figure 1.

SIMULATION

Test Network

The enhanced expansion planning approach was tested on a network based on a modified 12 bus rural distribution network (shown in Figure 2). The network is approaching maximum capacity and connection of DG without control would be subject to significant constraints at certain times when demand is low. The approach identified that actively managed DG could actually defer network investment by years with using power factor control and/or curtailment as a method of network management.

To illustrate the approach an increase in demand is required at the end of the 15 year planning horizon. Table 1 provides the final load data used with an annual demand growth of 5%. To facilitate comparison with the earlier work [2] all costs (in $) are retained.

Table 2 - Maximum demand at each bus at the end of 15 year planning horizon

Bus	Initial Max Demand (MW)	5% Increase Max Demand (MW)
2	5.41	11.25
3	1.93	4.01
4	0.06	0.12
5	18.40	38.25
6	1.96	4.07
7	1.90	3.95
9	0.55	1.14
10	2.70	5.61
11	2.85	5.92
12	0.81	1.68

Table 4 - Scheduling of new branches required along the 15 year planning horizon with no DG and 5% annual demand growth

Branch	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
2-3	Upgrade	2 x 60	120	12.5	6	2114.88
2-4	Parallel	1 x 35	96	18.5	0	1776.00
3-4	Upgrade	2 x 60	120	8.8	6	1488.88
4-5	Upgrade	1 x 60	120	2.1	8	158.11
8-9	Parallel	1 x 35	96	10.1	7	644.84
9-10	Parallel	1 x 35	96	22.3	4	1605.71
					Total	7878.42

Results

Initially running the simulation with no connected DG provides the minimum timeline for reinforcements required to maintain a safe and secure operation with a 5% annual demand growth. Table 2 represents the cost associated with infrastructure upgrades required for this benchmark condition, which is later used to determine the level of investment deferral achieved by permitting DG as an alternative to network reinforcements. Inserting 5MW of firm DG at Busbar 11 and running the simulation again, provides an investment deferral of 12%, as demonstrated in Table 3. This shows that each of the reinforcements is deferred by a minimum of one year and in some cases as much as 4 years.

Incorporating active control in the form of the sensitivity factor controller facilitates an additional 4% of investment deferral, thus raising total investment deferral to 16%. Table 4 shows that this results from delays to reinforcements at most branches, typically of one year, however, branch 2-4 does not see additional deferment from this control scheme. Figure 3 clearly demonstrates the increase in investment deferral from firm and actively managed DG.

Table 1 - Scheduling of new branches required with non-controllable DG

Branch	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
2-3	Upgrade	2 x 60	120	12.5	7	1995.17
2-4	Parallel	1 x 35	96	18.5	3	1491.16
3-4	Upgrade	2 x 60	120	8.8	7	1404.60
4-5	Upgrade	1 x 60	120	2.1	9	149.16
8-9	Parallel	1 x 35	96	10.1	9	573.90
9-10	Parallel	1 x 35	96	22.3	8	1343.16
					Total	6957.16

Table 3 - Scheduling of new branches required with controllable DG

Branch	Type	Capacity (MVA)	Cost/km (US$k)	length	year	PV cost (US$k)
2-3	Upgrade	2 x 60	120	12.5	8	1882.24
2-4	Parallel	1 x 35	96	18.5	3	1491.16
3-4	Upgrade	2 x 60	120	8.8	8	1325.09
4-5	Upgrade	1 x 60	120	2.1	10	140.72
8-9	Parallel	1 x 35	96	10.1	10	541.42
9-10	Parallel	1 x 35	96	22.3	9	1267.14
					Total	6647.77

DISCUSSION

Drawn from the results presented in this paper, it is possible to achieve additional investment deferral by including the decentralised adaptive control scheme within the expansion plan. Reinforcements are deferred by connecting DG which can effectively offset the increase in demand. Nonetheless, there becomes a level of DG which will then become a driver for reinforcements. However, this can be mitigated by the inclusion of actively managed DG, such as the adaptive control mechanism.

By including a method of controlling the output of the DG at times when network violations occur can save a further 4% of investment deferral or $309,000 in monetary value. Over a larger section of network or over various smaller networks, it offers substantial opportunities for capital saving.

CONCLUSIONS

This paper presents an enhanced expansion planning control mechanism. The mechanism is examined on a modified 12-Bus rural distribution network. From the simulations executed, it can be demonstrated that by incorporating active network management techniques within the planning strategy, further investment deferral can be achieved. This would release further DG capacity which currently is unavailable under existing "fit and forget" planning arrangements.

Acknowledgments

This work is kindly funded by an EPSRC Studentship and the School of Engineering, University of Edinburgh.

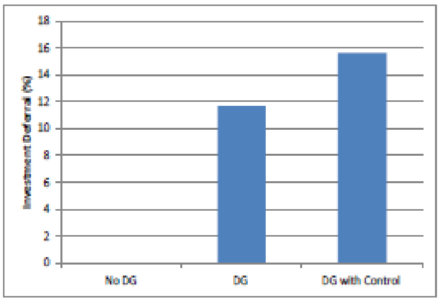

Figure 3 - Comparison of investment deferral for 5% increase in annual demand growth

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